Methods of Improved Selectivity and Control in Well Stimulation

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INTRODUCTION

The necessity and desirability of well stimulation has been apparent for many years. Many wells and fields would not be economical producers without modern completion and stimulation methods. To break this situation down even further, it can be said that where several porous zones are present in a well, each zone will not contribute its maximum production without proper treatment. With these things in mind, our purpose becomes very clear. It is simply to properly stimulate each porous zone or stringer in the pay section.

A number of methods have been employed to achieve this selectivity. Among these are packers, bridging plugs, straddle packers, and various forms of gels and other blocking materials. Tubing and packer methods are accompanied by reduced injection rates. Bridge plug methods require more time. Gel and blocking material methods are difficult to evaluate. Any of these approaches to selectivity involve considerable expense.

The Perforation Ball Sealer process has proved itself to be a simple, effective, and economical method for selectively treating the possible pay zones of a given oil or gas well. The purpose of this presentation is to outline the best known principles and procedures for reducing communication between zones and, therefore, achieving positive mechanical isolation of pay stringers during treatment.

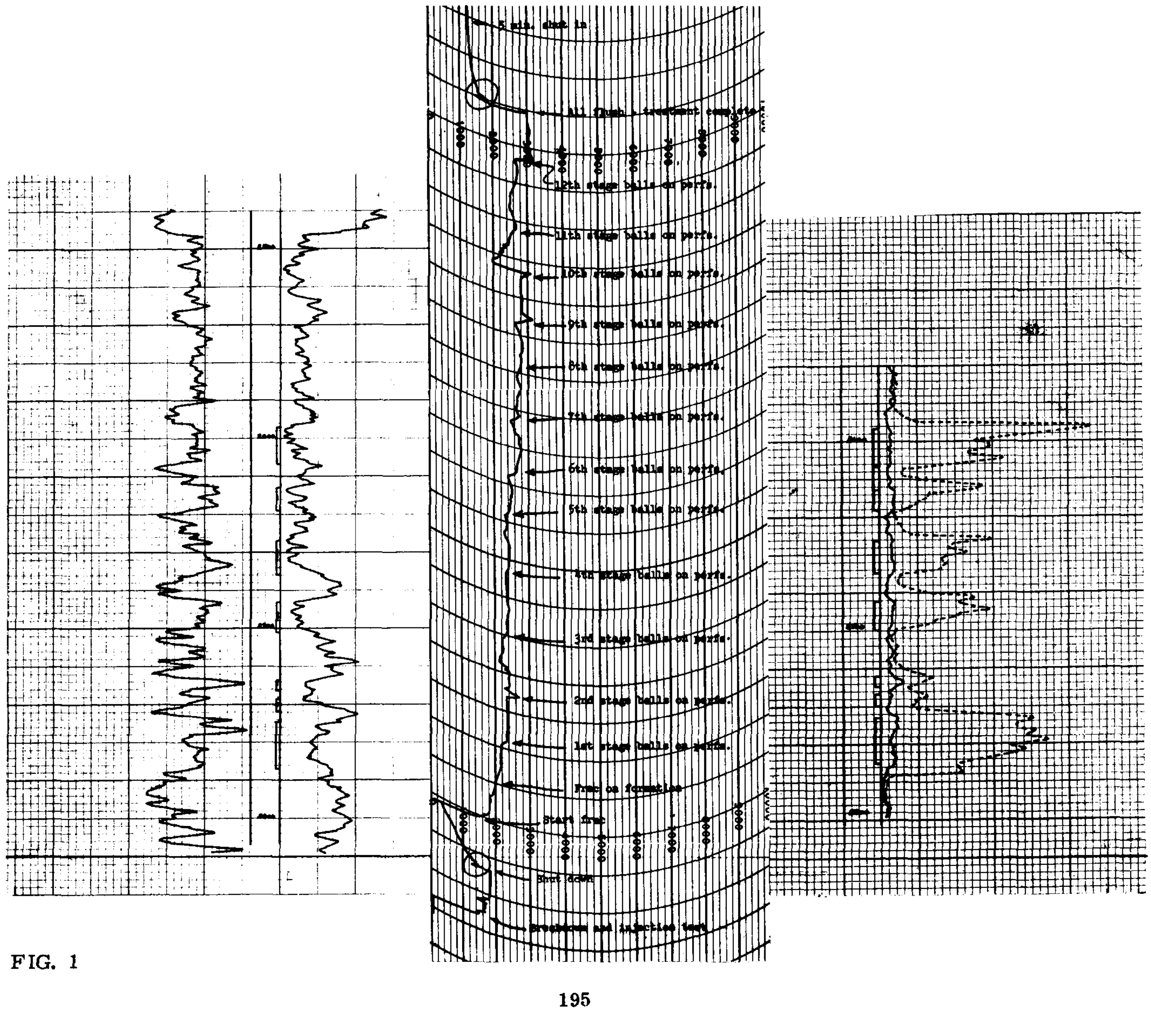

FIG. 1

PERFORATING CONSIDERATIONS

The proper perforating procedure is probably the most important phase of obtaining a selective job. In the past, the tendency to blanket perforate has greatly reduced mechanical control for selective treatment due to communication. When a fixed section of gross pay is encountered, the probability of creating more than one fracture is increased by perforating in intervals, and longer coment blanks tend to allow positive isolation of the porous zones. Due to our main objective of selectively treating the porous zones, it is as important to critically select the size and location of unperforated blanks as the location and size of perforated intervals.

An illustration of this objective is shown in Fig. 1. On the left is a Gammatron log showing the perforating intervals. In the center is a treatment pressure log showing increases and breaks as the Sealers shut off perforations and caused others to break down. On the right is a base Gamma Ray log (solid line) and a Gamma Ray after radioactive tracer material had been injected. This tracer log indicates that all perforated intervals received stimulation although there was evidence of communication surrounding the two small zones near the bottom where the unperforated blanks were short.

Positive vertical separation is dependent on three factors in a cased completion:

1. Strength of the Cement Bond -
   Operators have recognized the value of a good cement job, and have put more time and effort into obtaining the best possible cement bond. Hole diameter versus pipe diameter has been selected to achieve optimum cement thickness. To obtain better cement jobs, improved cementing materials were developed, the pipe was reciprocated or rotated during cementing, and acid has been used in some cases to clean the well bore prior to cementing. In addition to these, the wells are often perforated while the cement is "green" to reduce shattering effects. All or part of the aforementioned efforts tend to effect better isolation of zones.
2. Length of the Cement Blank -
   Longer cement blanks tend to reduce communications and provide positive isolation of zones. In this regard, less promising pay is often left unperforated in the interest of creating longer blanks.
3. Nature of the Rock Being Stimulated -
   Most pay stringers in the Permian Basin lend themselves to vertical isolation through proper selection of cement blanks; however, in some areas vertical fracturing exists and vertical isolation is difficult, if not impossible, in spite of long cement blanks.

Shot density may also be of critical importance in perforating for controlled treatments. A reduced shot density has less tendency to shatter cement, but, more important than this, it causes the treating fluid to go through fewer holes and thereby increases the ability of the perforations to attract Ball Sealers. From Fig. 2 we note that for 1 barrel per minute through a 0.5 inch perforation, there is a pressure drop across the perforation of 50 psi. The results in a fluid velocity through

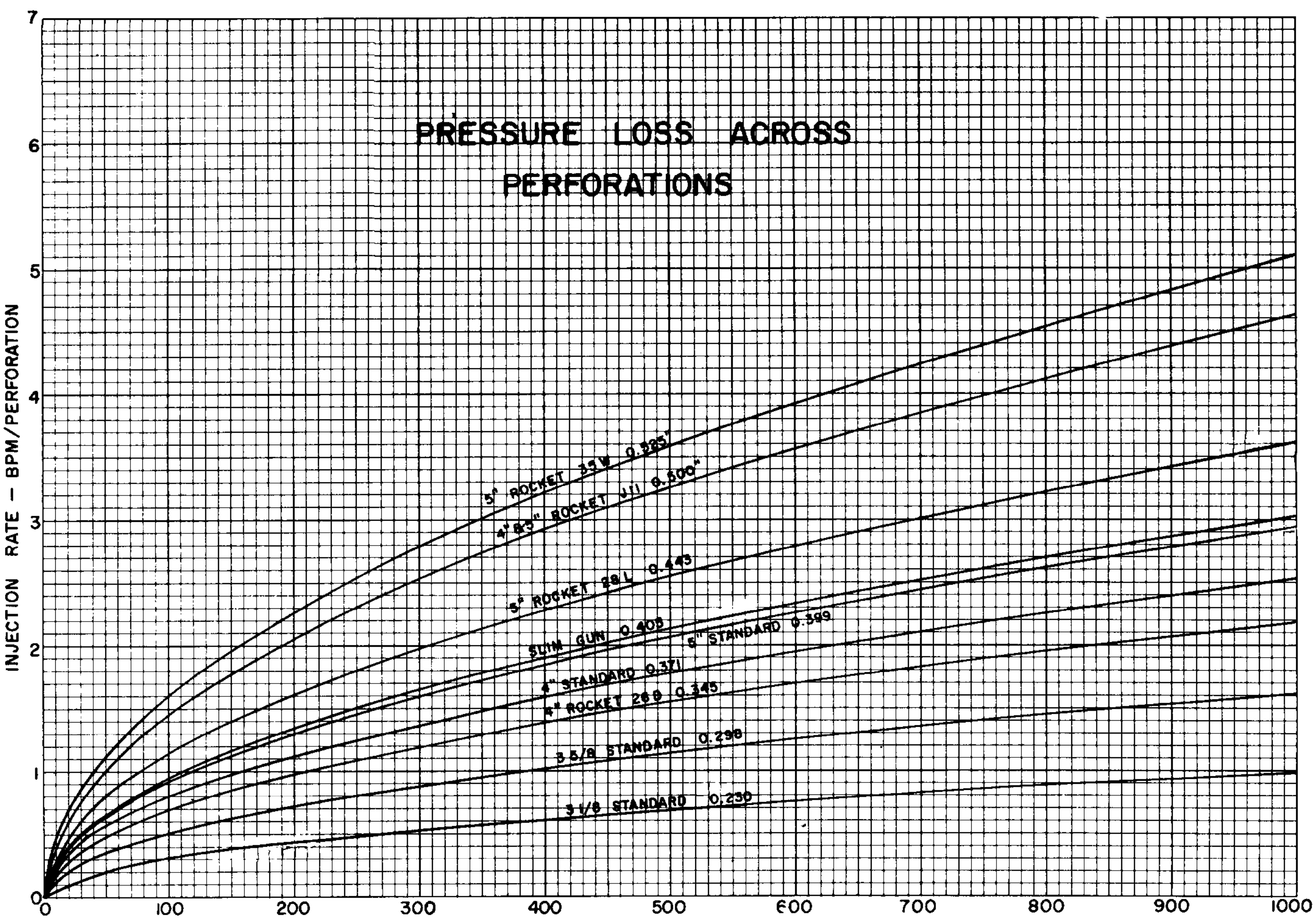

FIG. 2

the perforation of 68.5 feet per second.

From Fig. 3 we note that this fluid velocity through the perforation results in 100 per cent efficiency. In other words, if a situation can be created where a set of 0.5 inch perforations is taking an average of 1 barrel per minute per perforation, the loss is only a 50 psi pressure drop; yet, the Ball Sealers will not miss.

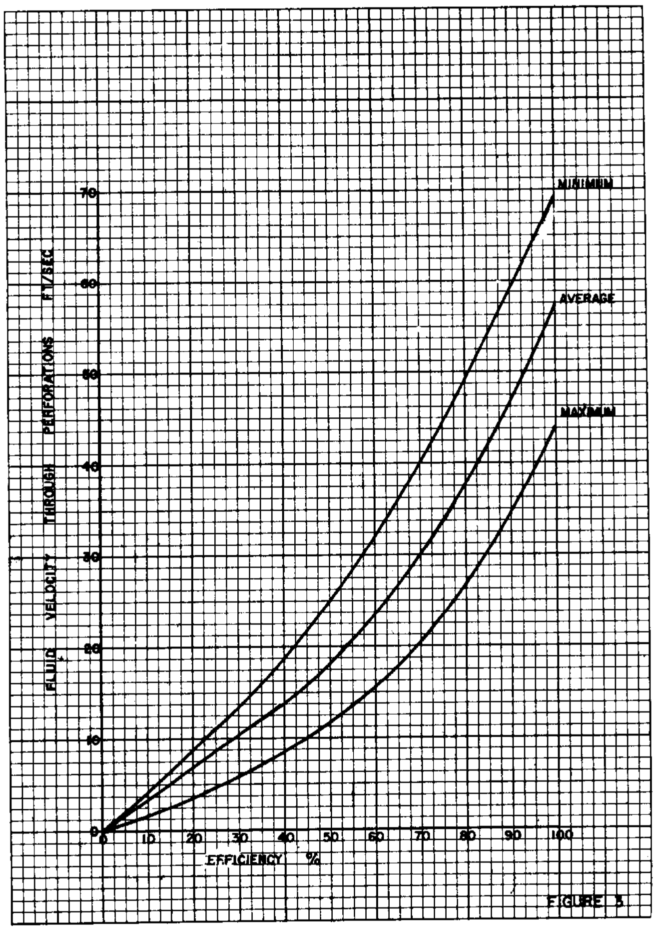

FIGURE 3

On the basis of choosing an optimum perforation size (0.5 inch to 0.55 inch in diameter) and varying the shot density to result in the proper number of holes per zone, excellent control can be achieved at a very small horsepower loss. Moving from this optimum condition in either direction, too many perforations tend to reduce control while too few perforations tend to create a bottom-hole choke and result in substantial power loss during treatment.

As shown in Fig. 4, normal perforating procedure would probably result in each pay stringer being shot with a standard shot density of four per foot, resulting in a sizeable variation in a number of perforations per zone. The second illustration in Fig. 4 shows the same pay section perforated four per foot, but with the same footage perforated in each stringer regardless of the thickness of the stringer. The third illustration shows each stringer perforated in its entirety, but with a variable shot density to result in the same number of holes per zone.

Assuming that a 40 barrel per minute treatment is to be used in this well, either of the last two methods would provide approximately the optimum number of perforations. A combination of these last two methods will normally allow the proper number of perforations to be put into pay stringers with maximum blanks and optimum number of perforations per zone.

Where smaller perforations are used, either more perforations per zone will be required or a higher differential pressure across perforations will be experienced. We have seen from Fig. 2 that 1 barrel per minute through a 0.5 inch diameter perforation requires 50 psi pressure drop. 1 barrel per minute through a 0.371 inch standard jet requires 160 psi pressure drop. This additional 110 psi pressure at 40 barrels per minute represents a loss of 107.6 hydraulic horsepower - (110) (40) (.0245) = 107.6.

Injection Rate

In Fig 3 we have seen the Ball Sealer efficiency is dependent upon fluid velocity through the perforations. It is often difficult to predict how many perforations are open, especially where a very large number of perforations are present. So we must often rely on "rules of thumb" regarding Ball Sealer accuracy. For a normal situation these might be: a small degree of accuracy at 3 to 4 barrels per minute; an accuracy of 75 to 80 per cent at 6 to 7 barrels per minute; and approximately 100 per cent accuracy at 15 to 20 barrels per minute and above.

Well Conditions

In some instances tubing and a packer will be necessary to reach the breakdown and/or treating pressures. One precaution in this instance is that the open ended tubing should be 20 or 30 feet above the top perforation. The tubing must contain no restrictions other than a seating nipple. Where high injection rates are desirable and high breakdown and treating pressures are common, many operators have chosen to use N-80 casing.

When wells are treated down both the annulus and tubing, Ball Sealers may be injected down the tubing or down the annulus. Of course when they are injected down the tubing, the volume of fluid required to place the Ball Sealers opposite the perforations is much smaller than that down the annulus. The most common application for Ball Sealers is with a high injection rate down the casing with no tubing in the hole.

Total Shutoff

As efforts are made to treat all or nearly all of the perforations, a higher ratio of Ball Sealers to perforations are used. This may occasionally result in a total shutoff or what is called a "ball-out." That is where all perforations that will take fluid are shut off and the maximum pressure is reached on the casing or tubing. Ball-outs are often intentional, and, when this occurs, you can safely say that all perforations have been broken down that will break down at the maximum pressure limitations with the fluid in use.

Ball-outs normally do not present a problem. It is necessary only to bleed off 2 or 3 barrels and thereby reverse the flow to allow the Ball Sealers to drop off and fall to the bottom so that the treatment can be continued. A valve should be provided at the well head and a bleed line to the pit for this purpose so that a minimum of time will be lost. If a given well does not have a sufficient injection pressure to flow back during treatment, then Ball Sealers cannot be reversed off and a ball-out will result in the treatment being stopped. This hazard is present only in a few low pressure areas.

Treatment Volumes

Since this method allows several zones to be treated in one setup, the amount of fluid used will normally be greater. The use of larger quantities of treating materials, equal to the total amount for all zones if treated individually, is recommended.

Stage Considerations

The actual running of the Ball Sealers should be conducted in stages rather than a continuous dribbling into the well. Regardless of the method used to determine the number and size of stages, the first stage should be the largest. This is because during the first stage of treatment there will normally be more perforations taking fluid than there will at any other time during the entire treatment.

After the first stage of Sealers hit and shut off all or part of the open perforations, a normal increase in pressure may be observed at the surface. This indicates that a tighter zone is open, fewer perforations are open, or both, and that a higher differential has been established from inside the pipe to outside the pipe. At this time we have established a high degree of accuracy, and smaller stages can be used.

Stage Design

There are two principal methods used to determine the number and size of stages. One could be called the "common denominator method." This method lends itself to wells with a controlled number of perforations per zone (Fig. 4), or wells where a common denominator may be quickly found for the existing zone perforations. An example of this is a well that has a 40 foot zone perforated four-per-foot, a 20 foot zone four-per-foot, and a 10 foot zone four-per-foot. In this case, the well could be considered to have seven 10-foot zones since the smallest is 10.

The common denominator method would dictate that seven stages of frac and six stages of Ball Sealers be used. The object of this being to get one stage of frac into each 10 foot zone, whether connected or not. However, we must realize that more perforations will be open on the original stage than at any time later. A typical stage design for this example would be 60 Sealers in the first stage and 40 in each of the five subsequent stages. This will allow 260 Ball Sealers to be used in treating the 280 perforations.

Another method which might be called the "pressure differential method" has been used successfully on a large number of treatments in the past few months. It should be used in wells where a large number of perforations are present and where there is a great variation in the number of perforations per zone. This approach is based on variations in pressure due to the number of perforations open at different stages during a treatment. Briefly, it is as follows:

1. An "instantaneous shutdown pressure" is determined from previous treatments or during the breakdown stage. This pressure is the surface injection pressure at zero injection rate. A surface injection pressure is established while

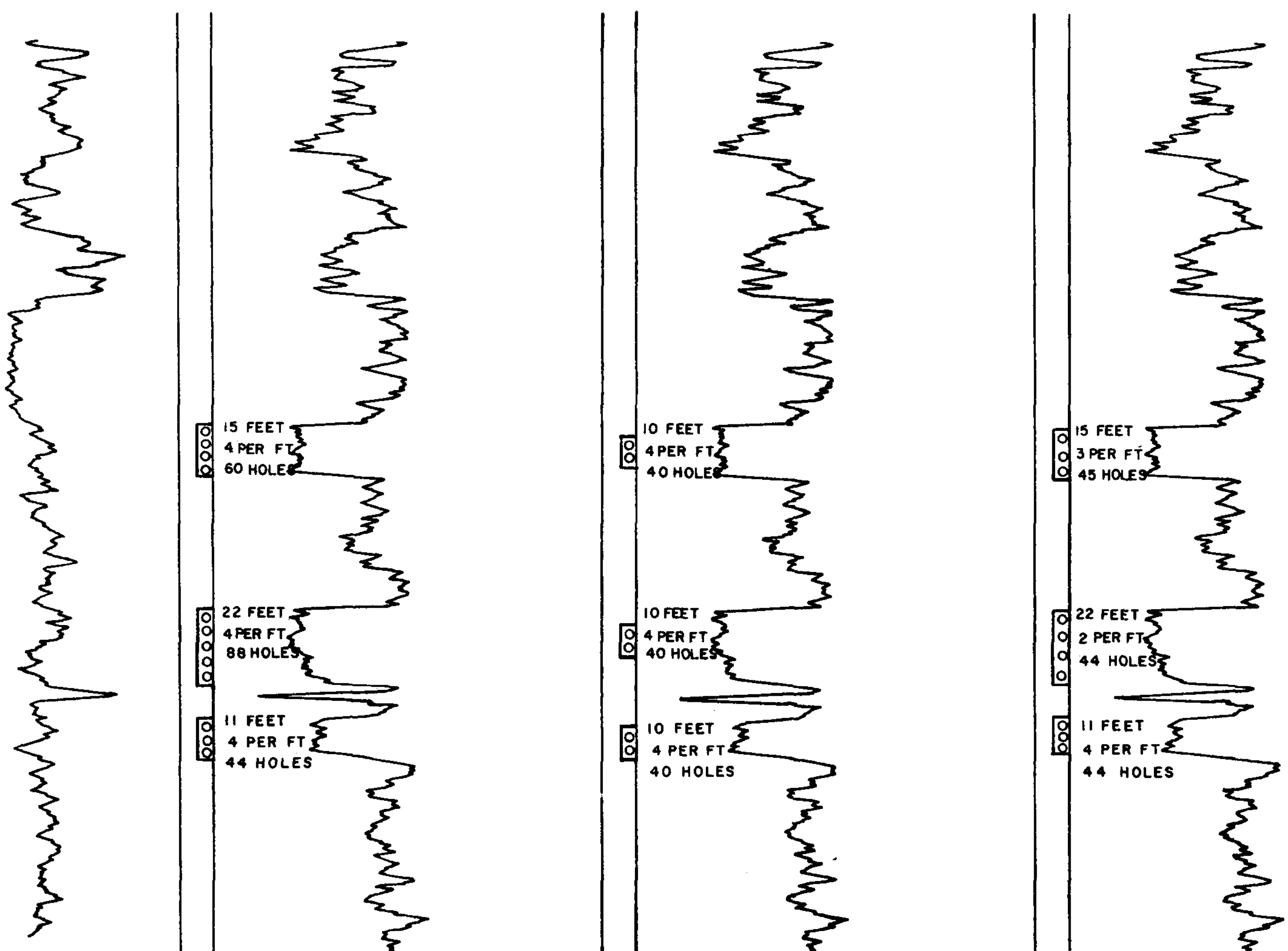

FIG. 4
NORMAL PERFORATING — EQUAL LENGTH ZONES — VARIABLE DENSITY

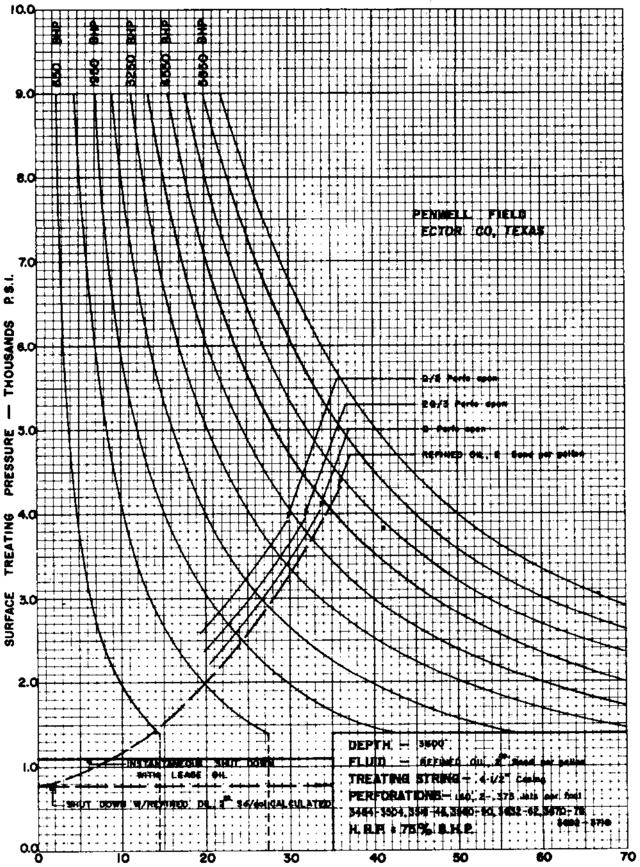

FIG. 5

pumping into the well. When the pumps are stopped, the line friction is lost immediately, and this pressure reading is the instantaneous shutdown pressure. These pressures are circled in Fig. 1, after the initial breakdown and one at the conclusion of the frac.

2. This pressure plus friction pressure at various injection rates is plotted on a chart which shows the available horsepower and corresponding injection rates at various pressures. A line is drawn through these points. The surface pressure reading should fall on this line regardless of the injection rate unless there is some additional restriction.
3. This possible restriction may be pressure drop across the perforations caused by a limited number of perforations being open. The extent of this pressure drop takes the form of parallel lines above the treating line on the pressure chart.
4. Using the known injection rates from the horsepower chart and observed pressures, we are able to tell how many perforations are open at a given time.

The pressure differential method can best be illustrated by an example, as shown in Fig. 5. This pressure chart was drawn for an engineered Ball Sealer treatment on a Penwell field well. The well had been treated with acid and flushed with crude oil, giving an instantaneous shutdown pressure of 1100 psi. The well data is shown on the chart. Refined oil with 2 pounds of sand per gallon was to be the treating fluid, so the first step was to correct the instantaneous shutdown pressure for the difference in hydrostatic head between the two fluids.

From Fig. 6 the hydrostatic head of the 33° API gravity lease oil is 373 psi per 1,000 feet. The head of the refined oil with 2 pounds of sand per gallon is 463 psi per 1,000 feet. The total differential in head, then, is 90 psi times 3.6 thousand feet, or 333 psi. Since the refined oil is heavier than the lease oil, this amount is subtracted from 1100 psi to give a corrected instantaneous shutdown pressure of 767 psi.

From Fig. 7 we obtain friction losses for injection rates of 10 bpm, 20 bpm, and 30 bpm, and multiply them by the average depth of the perforations in thousands (3.6 for 3600 feet). These are 414 psi, 1278 psi, and 2563 psi. Adding these to our instantaneous shutdown pressure we can plot a surface treating pressure of 1181 psi for 10 bpm, 2045 psi for 20 bpm, and 3330 psi for 30 bpm. Drawing a curve through these points, we now have a line on which the well will treat, assuming no restrictions through the perforations.

To incorporate the probable restrictions developed through the perforations due to the use of Ball Sealers, referring to Fig. 2, a standard jet perforation shows 160 psi differential at 1 bpm, 360 psi at 1.5 bpm, and 630 psi at 2 bpm. Parallel lines are drawn above the treating line to indicate these pressure drops, as shown in Fig. 5.

On casing treatments employing medium to high injection rates and a substantial number of perforations,

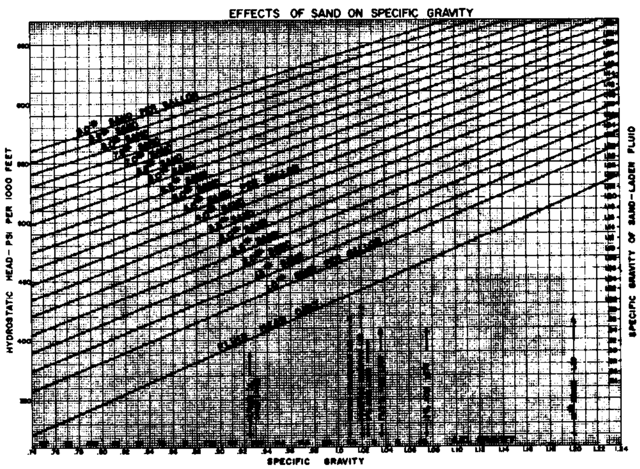

FIG. 6

it has been found logical to assume that there are approximately twice as many perforations open as the injection rate in barrels per minute. In the example shown, the injection rate was approximately 27 bpm using 4 pumps (2600 brake horsepower), and the well was treating on the base line, indicating very little perforation restriction. 54 Ball Sealers were injected, and no pressure increase was observed. The second stage of 54 Ball Sealers was introduced with no pressure increase.

A third stage of 54 Ball Sealers resulted in a 400 pound increase, but additional perforations broke down, and the well continued to treat near the base line. The fourth stage of 54 Ball Sealers resulted in a 500 pound pressure increase, which broke back to the Q line indicating that 1 bpm average was being pumped through the perforations open at that time. The injection rate was then approximately 26 bpm (from the intersection of the horsepower line and the Q line), and 26 Sealers were injected. The pressure increased 400 pounds and broke back to the $\frac{2Q}{3}$ line.

Eighteen Ball Sealers were injected, resulting in a 1,000 pound increase which broke back to slightly above the line. With the medium to high injection rate, approximately 100 per cent accuracy could be assumed, and 260 Ball Sealers had been injected. This would leave only 20 perforations to take fluid, and 12 to 15

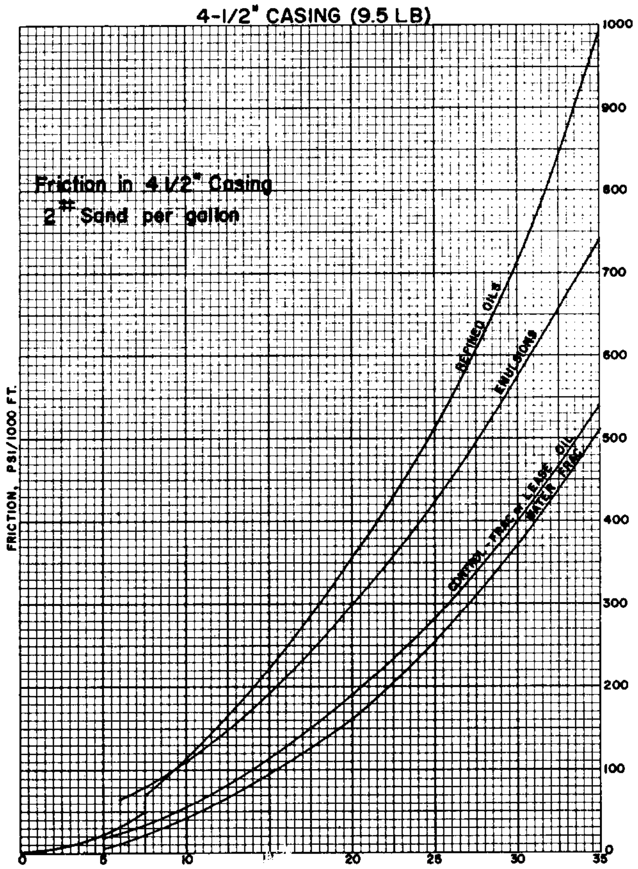

FIG. 7 INJECTION RATE, BBL/MIN.

were taking fluid. This "trackdown" method of selectivity had allowed all the zones to be treated, and essentially all of the perforations in each zone to be broken down.

Using either stage design method, if pressure increases are too great and the well is beginning to treat at too high a pressure, it may be desirable to reduce or delete some of the later stages. If, on the other hand, it appears that the pressure differential existent during the first stage of treatment was not great enough to attract and seal the Ball Sealers, it would be desirable to introduce a larger stage to gain an effective seal on the unusually large number of perforations open. Trained personnel and on-the-spot judgment is extremely important.

Advantages

1. Selectivity can be achieved without sacrificing injection rate in most cases.
2. This process utilizes the bottom-hole injection pressure to minimize pressure differentials across the cement blanks where we have been careful to create length and strength. As shown in Fig. 8 a well with a normal bottom-hole pressure of 1300 psi might require a 3300 psi injection pressure.
   This injection pressure bleeds off very slowly, probably not enough to detect in the short time required to shut off one zone, achieve a pressure increase, and break down another zone. This injection pressure tends to minimize pressure tends to minimize pressure differential across the cement blanks as contrasted to the high differential pressures often realized across packers and bridging plugs.

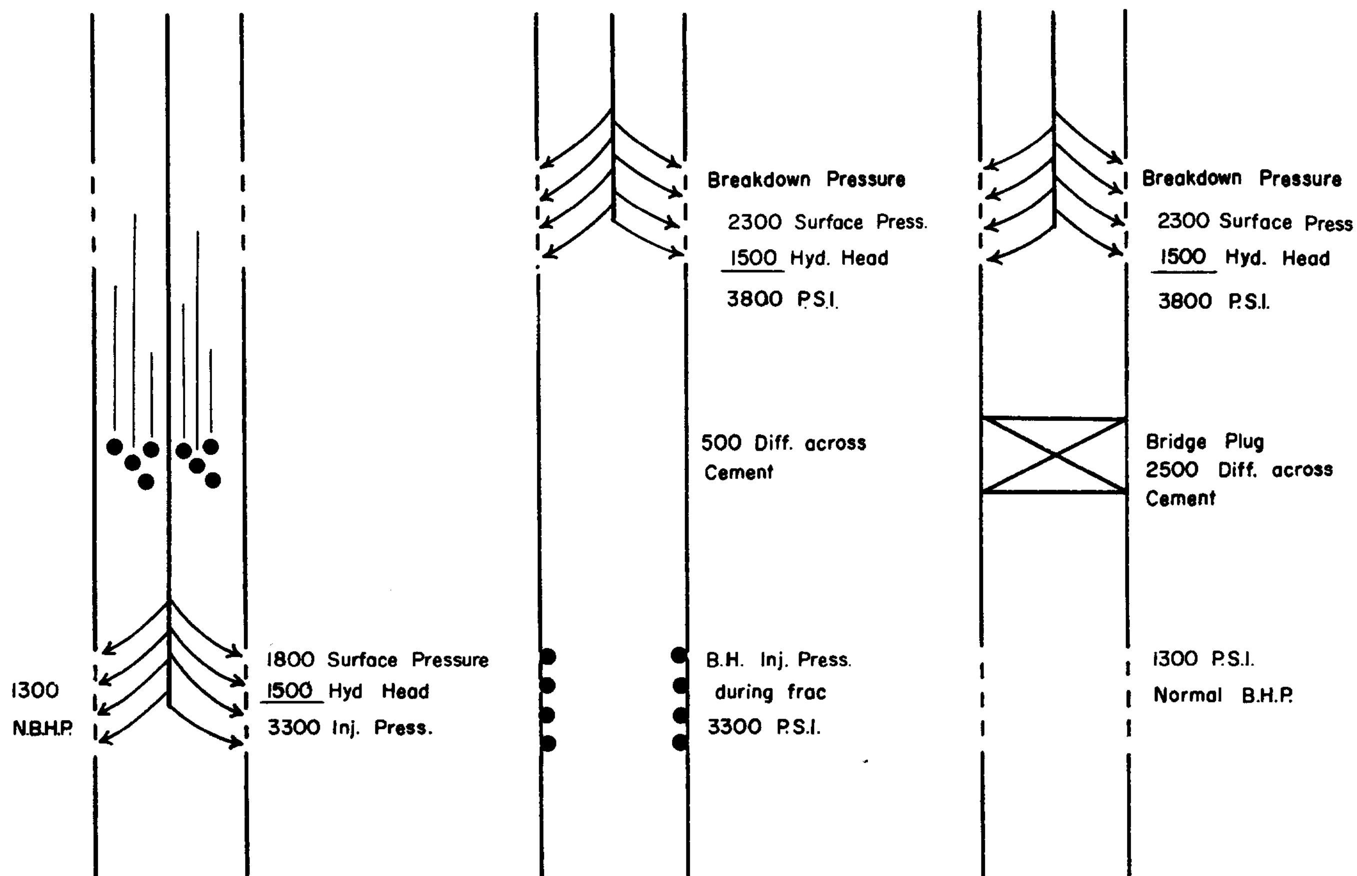

FIG. 8

3. Several zones may be treated by one setup, thereby saving rig time, operator's time, packer rentals, treatment set-ups, etc.
4. In many cases, although a zone is treated, only a small part of the perforations in that zone is broken down. This method will allow a very high percentage of all perforations to be broken down.
5. The Ball Sealers will provide a positive seal of perforations that are taking fluid. This positive, mechanical seal is far superior to the gambles involved with gels or solid blocking materials, or a combination of these. This is not to say that gels and blocking materials do not have their use--they certainly have. But it is generally agreed that positive, mechanical methods are superior where they can be used.
6. Ball Sealers are a removable selective treating means. They can be reversed off if desired.
7. There is little or no cleanup problem with Ball Sealers.
8. Last, but not least, is the fact that this selective process is very economically priced.

CONCLUSION

In conclusion, we can say that porous zones must be isolated and stimulated properly to achieve maximum results. In accomplishing this, perforating procedures, mechanical considerations such as well conditions, anticipated pressures, and injection rates are very important. Volume of treating fluid and stage determination contribute heavily to the overall treatment success and efficiency of the process.

The proper preparation of the well and treatment planning will allow the perforation Ball Sealer process to provide a much improved completion with less expenditure of time and money.