Primary and Remedial Cementing in Fractured Formations

By MAX GIBBS
Halliburton Company

INTRODUCTION

During the past several years oil well cementing practices have changed a great deal. Increasing demands are being placed on cementation methods as the search for oil goes deeper and becomes more complex. Secondary recovery techniques have required more effective designs to maintain control of injected water. Highly selective stimulation treatments have become the rule, and require maximum cement performance. In short, the whole area of oil well cementing has been subjected to intense evaluation.

The purpose of this paper is to consider the effect fractured formations will have on cement design, both primary and remedial. Numerous factors must be evaluated in any cement design, whether the affected formations are fractured or not, but so far as possible this discussion will be limited to specific problems presented by natural and induced fractures.

The Permian Basin of West Texas presents an excellent opportunity to study the effect of fractured formations on cementing design. Practically every formation penetrated in this area is fractured to some extent. The effect of these natural fractures is also aggravated by the induced fractures of the stimulation treatments so common throughout the Basin.

FRACTURING PRESSURE

The success of any cement design will depend primarily on an accurate evaluation of formation character. Probably the most usable characteristic is the pressure required to open or propagate a fracture through the formation. This fracturing pressure is usually quite predictable in a given field and often over a wide area. It can be readily determined from stimulation treatments, squeeze jobs, and in some cases lost circulation jobs. In short, any case where pressure at the point of fracturing is known is a source of this information. A considerable amount of this data is available from well files, and is often collected for treatment design. It is a valuable tool for cement design as well.

Fracturing pressure may be more usefully expressed as a pressure gradient. This is Fracturing Pressure/Fracture Depth or psi per ft. This expression permits a rapid comparison of fracturing pressure regardless of depth. In Table 1 the fracturing pressure and gradient of the Ellenburger formation is tabulated for a large area.

ELLENBERGER FRACTURING PRESSURE BY COUNTY

FIELD	COUNTY	DEPTH	FRACTURING PRESS.	FRAC. GRAD.
Wildcat	Loving	20,000	12,600	0.63
Keystone	Winkler	11,200	6,950	0.62
Wheeler	Ector	10,500	6,550	0.62
Wildcat	Ward	13,000	8,050	0.62
Wildcat	Pecos	21,500	13,750	0.64
Worsham	Reeves	17,500	11,200	0.64
Coyanosa	Pecos	16,000	10,250	0.64
Abell, N.E.	Crane	5,600	3,550	0.63

Table 1

Depths vary from shallow to extreme, and pressures also vary widely, but note that the fracture gradient is almost constant. It would seem that 0.63 psi/ft would be a close estimate of fracturing gradient in the Ellenberger wherever it was found within this area. Fracture gradients of other formations may be tabulated in the same way, and although different from this illustration, will be quite predictable over a large area. Table 2 illustrates a typical listing of gradients for different formations penetrated. It should be noted

FORMATION FRACTURE GRADIENTS

COYANOSA FIELD, PECOS COUNTY, TEXAS

FORMATION	FRACTURE GRADIENT
Rustler Anhydrite	0.65
Rustler Dolomite	0.70
Lamar Lime	0.58
Deleware Sand	0.58
Cherry Canyon	0.56
Brushy Canyon	0.58
Bone Springs	0.62
Wolfcamp	0.70
Penn.-Atoka	0.90
Mississippian	0.65
Devonian	0.63
Ellenberger	0.64

Table 2

that several of the formations listed here are of no interest so far as production is concerned. They are either barren or water bearing. However, they are of considerable interest in cement design and may require careful handling. Reliable gradient data are usually scarce for these formations, due to the absence of stimulation work, and emphasize the necessity of utilizing every possible means of collecting fracturing pressure information.

PRIMARY CEMENTING

The first problem ordinarily encountered in designing a primary cement job is determining which cement should be used. Various slurry or set properties may be required to accomplish the design objective, and many of these properties will be necessary whether the covered formations are fractured or not. The most common trouble encountered during primary cementing in naturally fractured formations appears to be opening or extensively fracturing these formations, and not accomplishing the desired annular fill. Producing zones may be severely damaged by cement invasion if they are the fractured sections. Regardless of how desirable some properties of a cement might be, if the annular column exerts more pressure than a formation is capable of standing the slurry cannot be properly placed, and the design is invalid. The basic problem in placing cement across fractured formations is determining what pressure may be applied to different sections of the hole without further fracturing.

The pressure exerted on the formation during a primary cementing job is a combination of hydrostatic and friction pressure. Usually the greater pressure change with respect to the drilling fluid is due to the density differences between the mud and cement. In some cases mud density may be near or equal the density of the desired cement slurry, and in this instance is a good index of the slurry that could be used. However, mud densities used in the Permian Basin are usually considerably lower than practical slurry densities. Drilling muds in the 9.0 to 11.0 lbs/gal range are the general rule in this area, and cement slurry weights of less than 11.5 lbs/gal are questionable at best. This leaves the designer in the situation of not knowing how much mud density can be safely exceeded by cement density without fear of fracturing. A trial and error determination of permissible cement densities through several field wells can be a very expensive solution.

Formation fracture gradients have been a very useful guide to cement selection.[1] If the fracturing pressure of each formation penetrated can be accurately predicted the design of primary cement placement is mainly a matter of controlling the pressure at different points downhole. The pressure at any point in the hole will be the total of mud and cement hydrostatic, and friction pressure above that point. Numerous combinations of components can be worked out, but their total cannot exceed fracturing pressure without impairing placement.

If cement is to be placed in a single stage, it is a simple matter to calculate the maximum allowable slurry weight and friction pressure. The lowest fracture gradient in the wellbore is the limiting pressure. Slurry weight must be limited to conform to this fracturing pressure. This will often mean low density slurries are required, with corresponding low strength, and effective cementation cannot be attained.

It is difficult to determine exactly how much set strength is required in a cement to provide effective cementation of casing in a wellbore. Simply placing cement with enough shear strength to prevent its being displaced from the annulus does not appear to be satisfactory in fractured formations. Most wells in this area require some stimulation, often extensive fracturing, during completion and the primary cement must be extremely competent if failure is to be avoided. Set strength is not the only cement property involved in this case, but higher strengths have consistently given better results than low strength cements in fractured formations. If all other factors are equal the highest strength cement that can be placed seems the most advisable.

In general, cement strength is synonymous with high slurry weight. The low water ratio slurries have the highest strengths. This brings us back to the problem of placement. A high strength, heavy cement may be required for good cementation, but exposed formations may not be capable of withstanding the necessarily high pressures of placement. More complicated methods of placement than single stage cementing may be required.

Several methods are commonly used in these instances to effectively place cement. Multiple stage cementers are probably the most common. Packer collars and aerated mud are also used in some cases. Design of these placements is considerably more involved than single stage cementing. Not only is the fracturing pressure of each zone important, but its depth and thickness must be considered. One approach to this type design is to determine the maximum slurry weights that

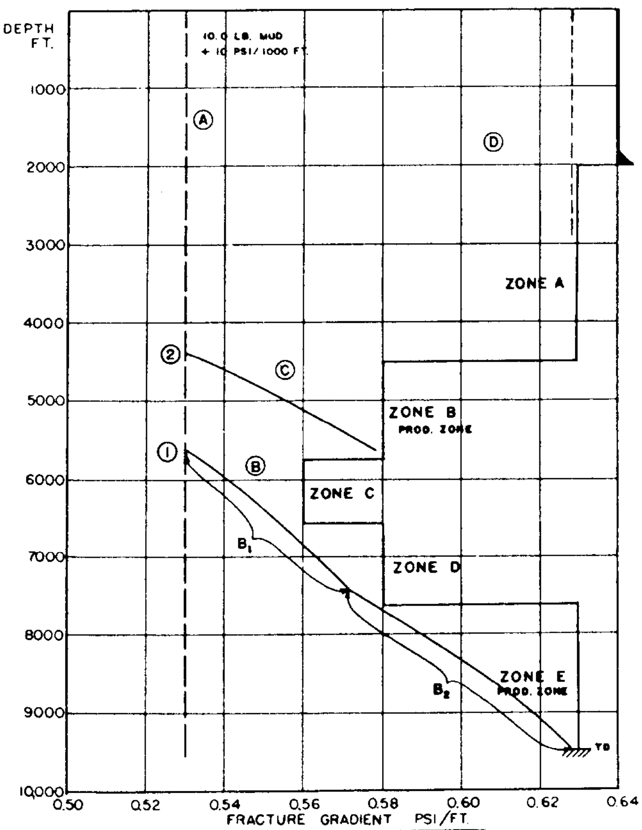

Fig. 1

can be placed. The sections covered may not require the strengths of maximum slurry weight. In these cases the final cement selection is made from other considerations; but in no case should placement pressures exceed fracturing pressure at any point in the hole.

Fig. I illustrates an application of fracture gradient data to placement design. The gradient of each formation penetrated is plotted versus depth to give a wellbore profile. The circulating mud gradient, including friction pressure, is plotted as line A. Zones B and E are potential producers and will require stimulation. The maximum slurry weights that should be placed are represented as a pressure gradient by line B. Section B, in this case, is a 13.25 lb/gal slurry plus 15 psi/1000 ft friction pressure. and B_2 is a 15.6 lb/gal slurry plus 20 psi/1000 ft friction pressure.[2] Point 1 is the stage tool setting of 4650 ft. Line C indicates the maximum slurry weight that can be placed across zone B, in this case 14.1 lbs/gal plus 15 psi/1000 ft friction. Point 2 may either be calculated top of cement, or if complete fill back to surface is required, a second stage tool, and the third stage cement would be represented by line D, which is a 12.0 lbs/gal slurry plus 10 psi/1000 ft friction. Numerous requirements other than those illustrated might be imposed on a design for this well profile, but regardless of other conditions, these fracturing pressures should not be exceeded. The use of these wellbore fracture gradient profiles has been a valuable tool in cement placement design, and warrants considerable effort in accurate determination and tabulation of fracturing pressure data.

The design factors described up to this point have been based on the assumption that loss of cement to the formation is due to opening of natural or induced fracture systems. There are some instances where the loss appears to be due to a combination of extensive existing fractures and low bottom hole pressure. The fracture system may not be enlarged, but still considerable cement is lost to the formation. This situation is most often encountered when cementing through a depleted producing zone.

Placement pressures should certainly be kept below fracturing pressure, but this alone may not accomplish effective placement. Some bridging or plugging material should be incorporated in the cement to stop the loss. The effect of these materials is difficult to predict, but some general conclusions can be drawn from their performance. A combination of granular and laminar particles appears to give better results than either type alone. A wide range of particle sizes is also necessary. Concentrations should be held as low as possible to prevent excessive filter cake thickness.

REMEDIAL CEMENTING

The design of remedial cementing in fractured formations is a much more diverse and complex problem than primary cement design. Often the most difficult analysis is determining what specific trouble exists. It would be impractical to attempt to discuss all the possibilities and combinations that might be encountered, and the procedures required to repair them. However, it might be worthwhile to consider some general approaches to repairing fractures systems, both natural and induced.

Again, an accurate analysis of formation character and a careful definition of the design objective is the first requirement. One of the first decisions to be made is: Is fracturing pressure necessary to accomplish cement placement? If so, is it necessary to maintain pressure above the fracturing point after cement is in place? The answers to these questions will have great influence on the selection of cement. The immediate question pertaining to cement is: Should water loss control be applied, and if so how much? The deciding factor is this case is usually formation permeability.

If fracturing pressure is necessary to place cement, water loss control may or may not be required. (If the fracture system is developed in dense, impervious rock, water loss control may be of little use; there is simply no place for water to go.) In fact, it might be desirable to increase water loss. On the other hand, if the rock is highly permeable, water loss control will be necessary to retain enough water in the cement slurry to keep it movable.

Formation permeability in the Permian Basin is usually quite low, in the 1 md to 50 md range. Many producing zones fall in the 0.1 md to 1 md class. These formations ordinarily require stimulation during completion, and the accompanying induced fractures account for much of the remedial work required. These fractures are usually vertical and communication between porous zones is common. Unless caution is exercised a vicious cycle is encountered. Stimulation causes communication, which requires cementing; improper cementing completely blocks the induced fracture system, restimulation is required, which again results in communication, etc. The objective of any remedial design must be to select a combination of techniques and materials to effect repair with an absolute minimum of cement, and realize as little formation damage as possible. The converse of this may be applied if a zone is to be abandoned, or is otherwise unwanted.

In addition to formation permeability, placement technique is also a deciding factor in determining the amount of water loss control needed. Low water loss slurries can be very efficient fracturing fluids. If they are used in impervious rock , and high pressures applied, the usual result is more fracturing. Assuming that fracturing pressure is required to place cement, is it necessary to maintain, or "hold" pressure above the fracturing point? Attempting to attain a high "standing" pressure with low water loss cements can be a frustrating procedure in low permeability rock, and excessive amounts of cement are pumped into the formation. Very little or no water loss control would be better suited to this case. A general conclusion has been that water loss control may be beneficial when placing cement at fracturing pressure, depending on permeability, but it seldom helps, and may be quite detrimental if high "standing" pressure is required.

The distinction made here between placing cement at fracturing pressure, and high standing pressure, is in how pressure is applied after cement is in place. Fracturing pressure may be necessary to open existing fractures to the extent cement can be placed in them, but when it is in place no additional pressure may be required to effect repair. Simply place cement in the fracture and allow it to set. This technique has proven quite successful for many repair jobs, and is coming into wider use. Attaining a high standing pressure is the conventional technique of placing cement at fracturing pressure, and continuing to pump cement until some predetermined, steady pressure is reached, usually considerably above fracturing pressure. Both techniques have good applications, but slurry properties should be carefully designed for each technique and permeability condition.

Since fluid loss additives have come into wide usage the general tendency has been to over-control water loss of cement in the low permeabilities of the Basin. At one time it was thought that water loss should be held in the 40 cc to 60cc range of a standard 325 mesh screen, 1000 psi differential filter press, regardless of formation permeability.[3] Recent trends have been to increase water loss to the 120 cc to 150 cc range and have been accompanied by better job results. In some of the lower permeability formations water loss up to 250 cc is giving good results.

Considerable remedial work is now being done with neither high standing pressure, nor fracturing pressure. A deliberate effort is made to avoid fracturing. This may require limiting the amount of cement, if a full tubing column will have sufficient hydrostatic head to fracture the formation. This technique is usually termed Low Pressure or Hesitation Squeeze.

The procedure generally consists of spotting cement across the offending formations, and applying pressure in gradual steps, allowing time for filter cake buildup, until some steady holding pressure just below fracturing pressure is reached. This design requires substantial water loss control, as very little pumpability can be sacrificed without increasing pressures. It is particularly applicable to induced fracture repair in or near producing zones. Long sections can often be squeezed off in a single stage that would normally require several stages using high water loss cements. Cement damage is minimized and recompletion problems alleviated. It is difficult to apply to low permeability zones because of the extremely long time required for filter cake buildup, but with proper water loss control it may have good application in stimulated zones.

CEMENT STRENGTH

Set strength is another important factor in selecting squeeze cement. In many cases the remedial work is being done to repair unwanted induced fractures, and restimulation will be necessary. Assuming that effective placement has been attained and the offending fracture is repaired, restimulation may place extreme stress on the repair. If the remedial cement is not competent to withstand these stresses the entire effort is wasted.

Determining the precise set strength necessary to accomplish a particular repair job is usually impossible, and is more a matter of selecting the highest strength cement that can be placed. Again high set strength is synonymous with low water ratio. The use of densified cement slurries containing dispersing agents to maintain pumpability has shown some promise as squeeze cement. These cements have extremely low water ratios, and compressive strengths in excess of 10,000 psi are possible. Care must be excercised in their use, as they are difficult to place; but they do have good application, particularly in heavily fractured, low permeability formations that require high fracturing pressures.

SQUEEZE PACKERS

The mechanical equipment used to place and control cement is a very important factor in designing remedial procedures. Each mechanical method of controlling placement should be considered when designing a job, and every effort made to place cement as specifically as possible.

As an example, consider the problem of squeezing off an induced fracture between two producing zones that must be isolated. Setting a packer above both zones and pumping cement into them may accomplish nothing except severe damage to productivity. Placing the packer between zones and circulating cement in the bottom, through the fracture, and up to the top zone should insure cement being placed in the fracture. Repairs of this type can sometimes be accomplished with very small amounts of cement, and little damage to production. This technique demands careful cement selection, lest the tubing be cemented in the hole, but will improve the chances of a successful repair, and may be worth the risk.

The selection of a squeeze packer usually resolves to the question of retrieveable versus drillable packer. Each type has its advantages; selection is governed by the design objective. It would be presumptuous to attempt to discuss all factors affecting squeeze tool selection; this should be done on an individual job basis, but some general review of performance is in order.

The greatest advantage offered by retrievable packers is their ability to be set and moved numerous times. Several zones may be cemented on the same trip in the hole. They are pulled from the well upon completion of a job, and do not have to be drilled out. Combinations of perforating, treating, and cementing can be done very economically in many cases. Their main disadvantage is their lack of control over pressure differentials. Once cement is started into the tubing the procedure must be carried to some conclusion. The cement is either displaced below the packer, or reversed out. The cement must effect shut off in the formation to prevent its flowing back during reverse circulating. If fracturing pressure is exceeded in low permeability rock, filter cake buildup may not take place fast enough to effect fracture shut off before cement thickening time has run out. When the packer is manipulated to reverse out, the fracture system relaxes, forcing cement back into the wellbore. This is usually the situation encountered when attempting to squeeze with low water loss cement reverse down through all perforations after squeeze pressure has been attained. If fracturing pressure is never exceeded, reversing back through perforations is more successful.

Drillable packers offer more control over cement after it is in place. They usually have a back pressure valve to help prevent fluid from flowing up through them, and can also be closed off from the top if necessary. Cement displacement may be stopped at any point during the procedure, and reversed out without disturbing cement already in the formation. This feature is important for low pressure squeeze work, and designs requiring placement at fracturing pressure but no standing pressure.

EXAMPLES

To better illustrate the application of the techniques described, some specific examples might be in order. These jobs are not typical, but extreme cases that illustrate some of the points previously discussed. Each procedure has been used several times; they are not isolated cases.

Case I

An injection well "short circuited" to a producer 990 ft away during stimulation. Injected water was rapidly produced. Remedial procedure was as follows: 100 bbls of gelled brine with 20 cc fluid loss tagged with radioactive tracer was pumped into the injection well above fracturing pressure, followed by low water loss cement (40 cc). A gamma ray tool in the producer indicated entry of gelled brine, and fixed the volume of the fracture at 95 bbls. Sufficient cement was mixed to fill two-thirds the fracture volume. Cement was overdisplaced 15 bbls and both wells were shut in. Pump rate was held constant throughout the job. Reperforating or stimulation was not required. Injection and production returned to normal.

This type of job has indicated that fracture volumes are sometimes small, and can be filled with relatively small amounts of cement. Cement may be placed in them easily, and if high pressure is avoided, little formation damage occurs.

Case II

Two zones 15 ft apart were communicating after stimulation. Two squeeze jobs failed to isolate these zones, as they required restimulation after each squeeze and communication reoccurred. When communication was noted after the last treatment, two squeeze perforations were shot midway between the two zones. A bridging plug was set above the bottom perforations, and a drillable packer was set below the top perforations. Fifteen gals of cement was pumped into the squeeze perforations and the packer was sealed. Neither producing interval was affected. Packer test indicated no communication after drill out.

These extremely small cement volumes have shown that effective repair of unwanted fractures is more a matter of correct placement than pressure or volume. They also illustrate the absolute minimum formation damage. It appears virtually impossible to maintain separation between closely spaced zones in many formations during stimulation. In some cases each zone can be stimulated effectively with existing communication, and separated afterwards, if sufficient control of cement can be maintained.

Case III

A drilling well lost circulation in 260 ft highly permeable, heavily fractured sand. Repeated plug back attempts failed. Cement would stay in the hole with near 100 per cent fill each time, recurring loss after each drill out. Low water loss cement was used with the same results.

The section was fractured with 300 bbls cement at a rate of 18 BPM with no water loss control and was shut in at zero pressure. After WOC 24 hours, the cement was drilled out with no loss and drilling was continued.

This situation is the exact opposite of the usual remedial job. Here the formation should be damaged as extensively as possible. Opening every natural fracture possible and placing cement in it constitutes considerable damage.

SUMMARY

Successful primary cement design requires accurate evaluation of formation character, and careful selection of cement properties to apply in each individual case. The property most affected by fractured formations is slurry weight, which largely determines placement pressure on the formation. Formation fracture gradients are a valuable aid in determining what pressures are permissible in the wellbore.

Remedial cementing is the more complex design, requiring careful control of placement as well as formation evaluation. The basic tenet in remedial cementing is to use only as much cement as is absolutely necessary to accomplish repair. This involves selection of cement properties, type of packers, and techniques of placement. Each item should compliment the others to fully accomplish the objective of the design.

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