PROPPANT SELECTION
USING DOWNHOLE PERMEABILITY MEASUREMENTS

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ABSTRACT

For worthwhile oil or gas well stimulation the best proppant and fluids have to be combined with a good design plan and the right equipment. Proppant selection is one of the important areas which determines how worthwhile and how successful the stimulation treatment can be.

To select the best proppant for each well a general understanding of available proppants is imperative. Also, the latest proppant properties for design are taken at downhole conditions with embedment, temperature, crushing and long term effects all being considered.

After downhole permeability of a proppant is measured, it becomes a logical process to narrow the selection of the proppant to a particular class and sub-class. With information from the downhole formation or reservoir the proper mesh size can be selected to fix the specific proppant, and optimize the hydraulic or acid fracturing treatment on the well.

INTRODUCTION TO PROPPANTS AND PROPPING AGENTS

The first frac jobs ever conducted showed better results when propping agents were used. In these early treatments river sand worked better than nothing and eventually clean sand was shown to work better than poorly sieved sand. After many years of usage, standard tests[1] were finally agreed to in 1983. Today, sand is categorized as premium, standard or substandard quality by American Petroleum Institute Recommended Practices (RP-56). Included in these procedures are many other tests that set the standards for fracturing sand.

Many engineers and companies have not been satisfied with using just sand as a proppant. Quality control has been inadequate some of the time and in deeper wells severe crushing, plugging and maintenance problems were experienced. A search began for other particles that might be useful as a propping agent. Some proppants that have been tried are nut hulls, plastic pellets of several varieties, aluminum pellets, garnet, steel shot and glass beads. For various reasons such as cost, availability or degradation the use of most of these proppants was not continued. Glass beads were widely used in the 1960's and 1970's until they were found to shatter catastrophically when tested under load in multilayer packs and hot brine. This property was not seen when tested in oil or air, and individually the glass beads were very strong. Glass beads[2] could not tolerate downhole conditions and that in reality is the final word. Their use was discontinued around 1976.

New proppants to replace sand or glass beads were introduced in the middle 1970's. These were curable resin coated particles[3] and sintered bauxite[4]. In this paper these proppants will be referred to as resin coated sand and ceramic proppants, respectively. Newer intermediate density ceramics have now replaced sintered bauxite and the resin coated sands now come in three flavors: curable[5], precured[6] or tempered[5], and double or high strength coatings[7].

For the rest of the 1980's proppants will continue to play an important role in hydraulic fracturing and acidizing. The quality control and standards for frac sands should be extended to the resin coated and ceramic proppants which are now widely used in the oil and gas industry.

UNDERSTANDING PROPPANT BEHAVIOR

Proppant Behavior

A simple lab test on proppant does <u>not</u> provide an engineer with the appropriate data to design a fracturing or acidizing treatment. All aspects of proppant behavior are difficult to measure. There are at least five (5) basic interactions that need to be examined for a complete picture of proppant behavior.

* Proppant to proppant behavior seen in multilayer packs
* Proppant to formation interaction seen in embedment
* Long term test effects seen in repacking and crushing behavior
* Downhole temperature and pressure effects shown by weakening, crushing and corrosion cracking
* Flow of fluid through proppants decreased by non-Darcy turbulent effects and contaminants such as degraded fluid gels and fluid loss additives

Unless the above effects are taken into account, there is a possibility that the wrong proppant or an inadequate proppant may be chosen.

Recently an industry group[8] made up of oil companies, service companies and manufacturers decided to conduct tests through an independent test lab to measure downhole permeability and proppant conductivity. These tests were run at typical downhole conditions of temperature and pressure for up to 300 hours. The tests were conducted in multilayer packs and the embedment effects were modeled using sandstone walls [Young's Modulus (E) = 5 to 6 x 10^6 psi]. Tests were further made with real fracturing fluids and fluid loss additives to achieve as realistic downhole conditions as possible. Future work will evaluate turbulence effects or non-Darcy flow under these same downhole conditions.

Previous lab tests of proppant data[9] have been made in stainless steel or Monel cells where permeability readings are dominated by wall and corner effects. These effects can be illustrated if we use uniform spheres (0.0331 in diameter). By using the Kozeny-Carmen law of porosity and permeability we can relate what is happening at the wall in terms of effective permeability by measuring the exact porosity as shown in Table 1. Where wall effects dominate, the Kozeny-Carmen equation shows that over 400 Darcys may be measured. The high permeability is a measurement of wall and corner effects in a cell that does not allow for any embedment. Other types of test cells that minimize wall effects show these uniform spheres to have about 100 Darcys permeability.

A full monolayer occurs at 0.3 lb/ft^2 loading. At this point the main measurement is the wall and corner permeability. As the proppant loading increases to multiple layers, the permeability and porosity decrease to lesser values. When embedment is present, the wall effect is lost. This in effect reduces the measured permeability.

Ceramic Particles

With a sample proppant of ceramic particles and all tests conducted at the same temperature and closure pressure (300° F and 10,000 psi), Table 2 shows the measured permeability reduced from high values with simple testing to low values with real downhole testing. Note that long term testing and the use of real fluids and additives causes an 83% reduction from the simple lab test between stainless steel plates. In other words, only about 1/6 of the original advertised permeability is left when tested realistically. The measured reduction is from 310 to 51 Darcys permeability.

Resin Coated Particles

There are three types of resin coatings applied to sand and other particles.

1. Curable Coating - bonds together thermally or chemically

2. Precured or Tempered Coating - for increased particle strength

3. Double Coating - inner coat is tempered, outer coat is curable to provide high strength and bonding in fracture

To understand resin coated particles we need to look at what they do and what they offer as good properties. Basically, any particle can be coated with a phenolic formaldehyde resin. This increases its strength and crush resistance as shown in Figure 1. Since the outer coating is partially cured for two of the three types of resin coated particles, they will bond together in the fracture to prevent flowback and embedment as well as crushing.

The reason resin coated particles improve the basic properties of the particles is that point-to-point loading is removed. Without stress concentration between grains, the resin coating improves the strength many times over. In effect, the pad of deformable resin between grains spreads the load evenly.

To test these particles more complex procedures are needed. Curable particles need to be cured in the test cell before an actual test as they would be in the fracture. Also, since the resin coating deforms to any type of wall in a test cell, wall effects in stainless steel or monel cells are minimal. Lab tests with stainless steel walls and with sandstone walls give very similar results. However, long term tests with actual degraded frac fluids and additives show a decreased permeability with about the same values as the ceramic particles in the same mesh size.

The first type of resin coating developed for proppants was a curable resin coating. The phenolic formaldehyde resin coating is integrally bonded to the underlying particle by a silane coupling agent which assures that the resin can not come off the particle. The coatings can be thermally or chemically bonded to lock all the particles together in the fracture. Bonded particles prevent proppant flowback and provide crush and embedment resistance.

The tempered or precured type of resin coating is advanced to the nearly cured stage. When resin coatings are tempered or precured, the strength and crush resistance increases to its maximum level. However, the precured or tempered coated particles do not bond or lock together.

Finally, in 1984 the advantages of both types of coatings were attained when the "HS" or high strength coating was introduced . A double coating is used to maximize strength but still bond the particles in the fracture with temperature and closure pressure. In manufacturing a tempered inner coating is applied to the particle. After cooling, a second outer curable coating is put on the particle. The final step in manufacturing is to screen, assure quality and send the particles to storage.

DOWNHOLE PROPPANT PROPERTIES

Permeability and Crush Resistance

Typical charts of proppant permeability and other properties are usually based on short term tests. These tests may be taken in air or water at room temperature or elevated temperature and are usually in some type of stainless steel cell.

For all practical purposes this data is worthless to the engineer or frac treatment designer. The new data for real downhole properties requires special test equipment and procedures. Figure 2 shows the old type of short term data of permeability versus closure stress on the left side combined with the real downhole (long term) data of permeability versus time on the right hand side. In Figure 2, Sample A is a typical clean 20/40 mesh sand used for hydraulic fracturing. The test conditions are 5000 psi closure stress and 225°F.

There are three points of interest on Figure 2 that should be noted. Point No. 1 is the short term permeability of sand at test conditions in a stainless steel cell and in a sandstone walled cell. Differences in test cells are minimal since sand crushing minimizes the wall effect. These values were all that have previously been available to design a treatment at these conditions. Point No. 2 shows the start of the effect of long term testing. This is considered to be due to proppant rearrangement, repacking and crushing. Point No. 3 is the final long term permeability or downhole permeability at 300 hours. From a practical point of view Point No. 3 is the only useful value of permeability for fracture treatment design. Note that further permeability reduction will be measured if degraded polymer gel and fluid loss additive contamination is present. Data of this type was not available at time of writing.

The behavior of ceramic proppants (Sample B) is shown in Figure 3. At point No. 1 on the graph the first discrepancy is seen during a short term test between tests in a stainless steel cell (no embedment) and a cell with sandstone walls (with embedment). The difference amounts to about 30% or a reduction from 310 to 217 Darcys. At point No. 2 the long term effects of compaction and rearrangement cause another drop until finally at 300 hours we get to point No. 3 which shows an effective permeability of either 105 Darcys with 2% KCl clean fluid or 51 Darcys with degraded HP Guar and silica flour in the 2% KCl. All tests were conducted at 300°F and 10,000 psi closure stress.

For economics, planning and the optimized job design the 51 Darcys is much more accurate and meaningful than the 310 Darcys. For 1987 and in the future insist on long term, downhole proppant design data.

Figure 4 shows double resin coated (high strength) proppant data under similar conditions (8000 psi closure stress and 275°F) and with sandstone walls. For all practical purposes the high strength resin coated particles give similar data as seen at point No. 3 in Figure 3 of the ceramic particles. Since permeabilities and fracture conductivity are similar for all high strength and resin coated particles, the frac designer can ignore claims of unusually high permeability attributed to bauxites and ceramic particles. Most proppants can now be fairly evaluated for practical downhole use. Also note that an additional permeability curve for 16/30 mesh double resin coated sand (high strength) shows extra permeability over the 20/40 mesh size of the same product. In certain wells where higher fracture conductivity is needed and when frac width is adequate, a change to the next larger proppant mesh size can be justified.

The crush resistance of all proppants should be measured at downhole temperature and at the expected maximum closure stress level of the particular well. Table 3 shows the relative crush resistance of several proppants at room temperature and at 300°F. Note that temperature does make a substantial difference in the amount of crushing. Only the curable and high strength resin coated proppants get stronger at higher temperatures since the resin coating locks the particles together to prevent free fines. All others decrease in strength as crush resistance decreases at the higher temperature. Sand and low density ceramics lose the most crush resistance at reservoir temperature.

Embedment

The loss of fracture conductivity due to embedment is well known; however it is often neglected in designing treatments. The results of many tests show that the harder the particle the greater the embedment. With embedment comes another problem which is the release of fines from the formation. A way of understanding this is to take a single particle and embed it into sandstone. A hard particle acts as a chisel to remove a piece of the formation. These pieces (fines) can contaminate the proppant pack and sometimes migrate to the wellbore.

It has been found that sintered bauxite causes the most severe embedment, intermediate density ceramics embed slightly less, sand less than the ceramics and resin coated particles embed least of all.

Single particles embed much easier than particles that are bonded together. Of course, the only proppants that bond together are special sub-classes of resin coated particles. Since bonded particles act as a solid, the result is a solid-solid interface between the bonded proppants and the formation.

Soft formations have the worst embedment. Embedment is noticeable when the Young's Modulus (E) is less than $6x10^6$ psi. Some highly productive gas formations in South Texas have Young's Modulus of less than $2x10^6$ psi.

The solution to embedment is two-fold. First, select the proppants that are permeable enough to do the job that embed the least. Second, use enough proppant in the fracture - called high proppant loading - to form extra layers of proppant that can be sacrificed to embedment.

Temperature

Temperature is known to adversely affect the crush resistance and effective fracture conductivity of certain proppants. Early tests for geothermal and other high temperature wells[11] showed the permeability of sand varied with both time and temperature. Glass beads were adversely affected by temperature when normal field brines and closure stress was present. This indicated the hot brine actually caused cracking by a corrosive type attack. With sand a similar effect is noticed; however, since sand is almost pure quartz and not as spherical or uniform in size the corrosive cracking affects are more gradual.

Even ceramics are somewhat temperature sensitive, particularly if low pH fluids are saturating the ceramic particles. When acid soluble components of the proppant are dissolved, the ceramic particle is weakened which results in more crushing and lower permeability. The resin coated particles are inert to both low pH and hot water effects. Because the particles become stronger as they bond together in the fracture the resin coatings protect the proppant better at higher temperatures.

The final proppant selection depends on temperature. Downhole tests of proppants should combine the maximum expected temperature and closure stress on the proppant. Also, a 300 hour test at downhole temperature assures the engineer of the future proppant behavior in the well.

Non-Darcy Flow

Flow through porous media and Darcy's law is in effect for oil or gas flow through the proppant pack. However, Darcy's law underestimates the pressure drop due to flow in the fracture when turbulence is present. To predict the extra pressure drop of turbulence the Forchheimer equation[12] is used. It can be written as:

$$\frac{\Delta P}{\Delta L} = \frac{\mu V}{K} + \beta \rho V^2 \qquad (1)$$

where $\Delta P/\Delta L$ = the pressure drop in the fracture

μ = the apparent viscosity of the fluid

K = the effective permeability of the proppant

ρ = the fluid density

V = the fluid velocity

$\beta = b/K^a$ where a and b are curve fit by data and K is the effective proppant permeability (2)

If the β term goes to zero, the Forchheimer equation simplifies to Darcy's law. From the new consortium data most of the high strength proppants (20/40 mesh) have effective downhole permeabilities of about 60 Darcys. Using this in Cookes[13] method we find that b = 2.65 and a = 1.54. Using all of these values β can be found to be:

$$\beta = \frac{2.65}{60^{1.54}} \text{ or } 4.85 \times 10^{-3} \frac{\text{atm-sec}^2}{\text{gm}} \qquad (3)$$

The effect of non-Darcy flow was calculated by a non-Darcy factor[12] (F_{ND}) defined as:

$$F_{ND} = \frac{\Delta P_D}{\Delta P_T}$$

or

$$F_{ND} = \frac{1}{1.0 + \left[2.492 \times 10^{-7} \left(\frac{\beta \rho K_f}{\mu}\right) \left(\frac{QG}{h_f w}\right)\right]} \qquad (4)$$

where
ΔP_D = Darcy pressure gradient (psi/ft)
ΔP_T = Forchheimer pressure gradient (psi/ft)
β = turbulence factor or coefficient of internal resistance (atm-sec^2/gm)
ρ = fluid density (lb/ft^3)
K_f = downhole proppant permeability (Darcys)
μ = fluid viscosity (cp)
Q = surface flow rate (scf/D)
G = gas gravity (air = 1.0)
h_f = fracture height (ft)
w = fracture width (in)

To apply the non-Darcy factor in Equation 4 it is multiplied times a suitable dimensionless conductivity ratio. For example if we use Cinco's[14] dimensionless conductivity (C_R) defined as:

$$C_R = \frac{K_f W_f}{\pi K L_f} \qquad (5)$$

where
K_f = downhole proppant permeability (Darcy)
w_f = fracture width (ft)
K = formation permeability (Darcy)
L_f = fracture half-length (ft)

then the effective non-Darcy dimensionless conductivity (C_{RE}) of Cinco's can be written as:

$$C_{RE} = F_{ND} \cdot C_R \qquad (6)$$

Various authors[15,16,17] have found if C_{RE} is reduced to a value much less than 1.0 then production from a given well may be reduced by a substantial amount. High residual water saturation compounds non-Darcy flow effects and can reduce flow rates (or increase β factors) even more.

Contamination

Contamination can occur in many different ways. Anything that lowers proppant permeability or conductivity is a contaminant. There are natural contaminants which occur merely by the tensile fracture of the formation. Estimates as high as thousands of pounds of these formation pieces or fines have been made. Most are pushed away from the wellbore during the actual treatment but natural fluid leak-off can lock some of these against the fracture face where they can later mix in with the proppant pack.

Other contaminants are degraded polymers like guar, HP guar and other materials which concentrate as the fluid leaks off during the fracture treatment. The polymer gels leave residual traces of glue-like material after degradation and can definitely plug the proppant pore spaces.

Fluid loss additives are solid particles intentionally added to form a filter cake and slow frac fluid leakoff during the treatment. Most remain after the job and provide some amount of contamination to the fracture conductivity.

In the consortium tests mentioned earlier an interesting observation was made. Most of the contamination was found after long term downhole testing in the proppant layer next to the formation face. The contamination upon examination included degraded polymer residue, fluid loss additives and formation fines caused by the embedment of the proppants.

While actual prediction of downhole contamination will be difficult, the design engineer should understand the mechanism of possible contamination. One possible solution is to increase proppant loading in the fracture (larger number of layers of proppant) so that the proppant contaminated at the wall will not prevent free flow through the majority of the proppant pack. Many authors[18,19] have shown that a well designed fracture has enough area to easily drain the formation even with severe fracture face damage.

PROPPANT SELECTION

Selection Based on Downhole Conditions

The downhole conditions of each oil and gas well are different. For each type of well, different types of proppants are appropriate. The most straight forward approach to proppant selection is to look first at the bottomhole temperature of the well. This value if not known exactly can be easily estimated by depth correlation, temperature gradients and service company experience. Next, the maximum expected closure stress of the formation which can be estimated as:

$$CS_{MAX} = (FG_{MAX} \cdot D) - BHPP_{MIN} \quad (7)$$

where CS_{MAX} = Maximum Closure Stress (psi)

FG_{MAX} = Current Fracture Gradient (psi/ft)

D = Depth (ft)

$BHPP_{MIN}$ = Bottom-Hole Producing Pressure (psi)

With these two values estimated go to Table 4, the Proppant Reference Guide which shows available proppants for these ranges of temperature and pressure.

Select Class

There are three (3) basic classes of proppants: sand, resin coated particles and ceramics. More than one class may be suitable for a particular well. Again Table 4 will show the commercially available proppants and how each class may overlap for each particular downhole condition. Cost and availability control the selection of the class of proppant. More than one class of proppant may be suitable for any given well.

Select Sub-Class

Sand, resin coated sand and ceramic proppants are available in several types which will be called sub-classes in this paper and illustrated in Table 5. Each sub-class may or may not be appropriate for a given well. Some guidance can be gained from current practices, consultants, manufacturers and service company personnel. Also the normal sub-class of proppant that is used may not be ideal - particularly if crushing, flowback or embedment is causing less than optimum results. The selection of the sub-class depends on what type of well problems are to be solved; however, cost and availability are still major factors in the selection process.

With sand, the change of sub-class may be illustrated by going from a substandard or standard to a premium sand, and this may result in better long term results. The resin coated sands have sub-classes of different functions which solve different downhole problems. The main difference in the sub-classes of resin coated sand is whether they are bondable or not. Other differences are custom designed coating, high strength, double coatings and particle shape.

Ceramics have several sub-classes which generally are differentiated in terms of density. Usually the ones considered higher strength have the higher density.

Table 5 lists the class and sub-class of particles that are generally available; however, some special sub-classes may have been inadvertently left off.

In summary, select a sub-class or proppant which solves as many of the wells problems as possible. If crushing is a suspected problem, discontinue sand and select resin coated sand or a ceramic particle. If flowback is causing loss of stimulation or maintenance problems, select a curable (bondable) resin coated sand that will not flowback. If embedment is a problem, minimize the problem by selecting a proppant that minimizes embedment or by using higher proppant loading (more layers of proppant).

Select Mesh Size

The most specified mesh size is 20/40. However, 12/20 and 40/70 are other standard mesh sizes commonly used. In certain instances 16/30, 16/20 and 8/16 mesh proppants are selected. Mesh size selection depends on the downhole formation permeability and the design fracture length. For design purposes a cross plot of Cinco's[14] conductivity term and the McGuire Sikora chart[22] is used as shown in Figure 5. By using long-term downhole permeability mesurements (sandstone walled test cells) as the proppants permeability in Cinco's conductivity term shown in Equation 5, a practical example can be worked out.

Assuming 600 feet for the propped fracture half length, 60 Darcys permeability for 20/40 mesh ceramic or resin coated sand, frac width 0.2 inches and formation permeability of 0.5 md Cinco's conductivity ratio can be calculated:

$$C_R = \frac{K_f W_f}{\pi K L_f}$$

$$C_R = \frac{60. \quad (0.2/12)}{\pi \ (0.0005) \quad (600)}$$

$$C_R = 1.061$$

If C_R is between 1 and 10, the fracture conductivity is sufficient to allow almost full production. Severe restriction to flow is measured when the C_R is less than 1.0. In this example slightly higher conductivity ratios could be obtained by a higher proppant loading of the current proppant or by going to a larger proppant such as a 16/30 mesh resin coated sand or ceramic.

On the McGuire-Sikora Chart in Figure 5 the shaded area is the preferred design zone. Most optimized treatments by economic experience, by well testing and by reservoir analysis will reside in the shaded portion of the chart.

Extremely large jobs or jobs on extremely tight formations may fall on the right side of the graph and shaded area. Proppant selection combined with economics and experience can result in a treatment that is optimum. Many times the first well treated in an area will not be optimum and subsequent jobs can alter class, sub-class and mesh size of proppants. Also, other factors such as the type of fluids, volumes and rates may need to be altered.

In summary, select the mesh size that will fit into the fracture. The generated fracture width should be at least two to three times the diameter of the largest grain. Use only the downhole permeability value for a given mesh size particle. For example, at 10,000 psi, 300°F a 20/40 mesh ceramic particle has only about 50 to 60 Darcys not 310 Darcys permeability. In any economic calculations or reservoir simulators use a realistic value of permeability to get realistic results.

PROPPANT USE

Optimize Results

To optimize well stimulation treatments the right proppant must be selected along with the right amount of proppant. Assuming the fluid has already been chosen there are several factors to consider in proppant selection. These are:

* Proppant Loading
* Proppant Transport
* Proppant Degradation
* Proppant Maintenance

Each of these affect the final outcome of the treatment and could aggravate problems with the wells future production.

Proppant Loading

Each fracturing fluid can carry up to a certain amount of proppant per gallon of fluid pumped. In South Texas 10 to 12 pounds of proppant per gallon is common practice. With these concentrations of proppants up to five (5) pounds of proppant can be placed in each square foot of the fracture. High leak-off rates can cause screen outs or sand outs and this of course would prevent the use of such high proppant loadings. Problems with screen outs are quite common in fractured reservoirs and with various unstable gelled fluids. Adjustments to the proppant design and fluid design is usually necessary in these cases.

In softer formations at least 2 lb/ft^2 proppant loading in the fracture is recommended so that embedment will not substantially reduce oil or gas flow. When proppant loading is less than 1 lb/ft^2, soft formations can completely plug the proppant flow paths. In hard formations a design using 1 lb/ft^2 or more is usually considered sufficient.

Keep in mind that higher density particles require more particles to form a multilayer proppant pack. At the extreme almost 25% more pounds of sintered bauxite is required to fill the same volume as resin coated sand.

Proppant Transport

The specific gravity of the particle and its diameter determine how well any fluid will carry the proppant out into the fracture. The choice of the class of particle determines a range of specific gravity and with the ceramics a choice must be made of a particular sub-class to pin it down. The mesh size determines the particle diameter. Table 6 shows the relation of mesh size and particle diameter.

By knowing Power Law parameters of the frac fluid (n', k') particle and fluid density, and the proppant diameter there are several correlations that can be used to predict proppant settling. In Novotny's paper[23] the equation for settling velocity is:

$$V_s = \frac{(2n' + 1)d}{108n'} \left[\frac{(\rho_p - \rho_f)d}{72K'}\right]^{1/n'} \tag{8}$$

where
V_s = terminal settling velocity (ft/sec)
n' = flow behavior index of fluid in fracture
K' = consistency index
d = proppant particle diameter (in)
ρ_p = proppant density (lb/ft^3)
ρ_f = fluid density (lb/ft^3)

Proppant Maintenance

The best proppant maintenance is none. However, many times proppants can flowback, become plugged or cause wellbore maintenance problems. The proppant problems can usually be solved but not always inexpensively.

Proppant flowback is a problem in many areas[20,21]. It is caused by injecting a near spherical particle that can roll back out of the fracture or can be pushed out by the closure stress. It can cause surface maintenance problems like erosion and abrasion of tubing, chokes and valves. However, the main problem is the evacuation of proppant near the wellbore. Because it is not replaced, the fracture can close or heal. This causes a loss in stimulated production which is documented in Raymond and Binder's paper[24]. Prevention of flowback is possible by restricting the wells flow rate or by using a curable resin coated proppant that bonds together. When flowback has already occured, a solution is to refrac the well with viscous frac fluids and a curable resin coated proppant to reopen the fracture and lock everything together in a conductive fracture.

Occasionally, proppants become plugged with formation fines, fluid loss additives, parafins, asphaltenes and/or degraded polymer gels. Prevention of this is not always possible, but minimization of this effect can be made by using tapered gel schedules, the minimum required additives, and tests to assure frac fluid and reservoir compatibility. A solution to an existing problem is to treat the already fractured well with acid or other dissolving chemicals. These fluids are injected below frac pressure if loose particles have been used as proppants; however, high rates and pressures are permissible if curable proppants are in place in the fracture. Since these are locked together, they will not flow back away from the perforations.

When ceramics or sintered bauxites are used as proppants their flowback can cause severe problems of abrasion. In very deep, high pressure, high flow rate wells several solutions have been proposed. One way is to use a special choke manifold so that the well can be kept under control. The more effective way is to merely coat ceramic or bauxite particles with curable resin to lock them into the fracture. Resin coated ceramics have been used routinely in some of the highest productivity wells in South Texas. Production rates above 20 mmscfd have been reported with no flowback.

CONCLUSIONS

Proppant selection using downhole permeability measurements is very important to the hydraulic fracturing success of oil or gas wells. All aspects of proppant behavior should be understood to make the best selection.

Proppant selection is best made by using long term tests of proppant at downhole conditions of temperature and pressure. Special test cells use sandstone walls to account for embedment and more accurately simulate downhole conditions. Match the Young's modulus of the specific formation to the test cell walls if possible.

The proppant selection process can be summarized in the following steps:

1. The class of proppants is chosen as to availability and cost.

2. The sub-class of proppants is chosen to solve specific problems or potential problems in the well.

3. The mesh size is chosen based on <u>downhole permeability</u> of the proppant (note: do not use short term stainless steel cell test data) relative to the formation permeability and fracture length. By using with Cinco's Conductivity Ratio between 1 and 10 in the shaded area of the McGuire Sikora chart, a good stimulation treatment should result.

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NOMENCLATURE

$BHPP_{MIN}$ = Minimum Bottom-Hole Producing Pressure (psi)

C_R = Conductivity Ratio (-)

C_{RE} = Non-Darcy Conductivity Ratio (-)

CS_{MAX} = Maximum Closure Stress (psi)

D = Depth (ft)

FG_{MAX} = Current or Maximum Fracture Gradient (psi/ft)

G = Gas Gravity (air = 1.0)

h_f = Fracture Height (ft)

K' = Consistency Index for Power Law Fluid

K or K_e = Permeability Associated with Effective or Actual Permeability (Darcy)

K_f = Downhole Permeability of Proppant (Darcy)

L_f = Fracture Length (ft)

n' = Flow Behavior Index for Power Law Fluid

Q = Surface Flow Rate (scf/D)

r_e = Drainage Radius (ft)

r_w = Wellbore Radius (ft)

V = Fluid Velocity (ft/sec)

V_s = Terminal Settling Velocity (ft/sec)

w = Fracture Width (in)

W or W_f = Fracture Width (ft)

GREEK LETTERS

β = Turbulence Factor or Coefficient of Internal Resistance (atm-sec^2/gm)

$\Delta P/\Delta L$ = Pressure Drop in Fracture

ΔP_D = Darcy Pressure Gradient (psi/ft)

ΔP_T = Forchheimer Pressure Gradient (psi/ft)

μ = Apparent Fluid Viscosity (cp)

ρ_f or ρ = Fluid Density (lb/ft^3)

ρ_p = Proppant Density (lb/ft^3)

Table 1
Kozeny—Carmen Relationship of
Porosity to Permeability

Sphere Loading (lb/ft²)	ϕ (percent)	K_e (Darcys)
0.3	48.6	439.8
0.4	44.0	228.5
0.5	40.7	140.9
0.75	39.1	110.8
1.0	38.3	100.0
2.0	38.3	100.0
4.0	38.3	100.0

Table 2
Permeability and Percent Reduction of
Permeability Based on Short Term to
Long Term, Downhole Testing
of 20/40 Ceramic Proppants

Type of Test	Permeability (Darcy) @10000 psi,300°F	Reduction (%)
Short Term Test (Stainless Steel Cell)	310	---
Short Term Test (Sandstone Walls)	217	30%
Long Term Test (300 hr) in 2% KCl with Sandstone Walls	105	66%
Long Term Test (300 hr) in 2% KCl, degraded HP Guar and fluid loss additive with Sandstone Walls	51	83%

Table 3
Proppant Crush Resistance (20/40 Mesh @ 4.0#/ft²)

Product	Test Temperature	Percent Crushed		
		5000 psi	7500 psi	10000 psi
High Strength Dual Resin Coated Sand	75°F 300°F	0.53 0.00*	0.98 0.00*	1.80 0.00*
Sintered Bauxite	75°F 300°F	---- ----	---- ----	0.90 1.70
Ceramic** (IDP)	75°F 300°F	0.30 1.50	1.10 2.80	3.70 6.60
Precured or Tempered Resin Coated Sand	75°F 300°F	3.00 6.20	6.00 6.40	7.50 11.00
Curable Resin Coated Sand	75°F 300°F	3.10 0.00*	10.70 0.00*	21.30 0.00*
Ceramic *** (LDP)	75°F 300°F	0.30 0.60	1.20 3.90	7.10 18.40
Ottawa Sand	75°F 300°F	4.90 7.20	22.80 30.70	34.70 41.50

* Zero free fines since particles are bonded together
** IDP Ceramic is an intermediate density ceramic
*** LDP Ceramic is a low density ceramic

Table 4
Proppant Reference Guide

BOTTOM HOLE TEMPERATURE	CLOSURE STRESS	DESCRIPTION OF PRODUCT	NATURAL SAND COMPANIES	SANTROL PRODUCTS	ACME	STANDARD OIL PROPPANTS	NORTON
LOW 80-150°F	LOW 0 - 2000 psi	Angular sand, highest permeability.	Tuscaloosa Sand	n/a	n/a	n/a	n/a
		Curable resin-coated angular sand, highest permeability, lowest specific gravity, prevents flowback.	n/a	Super Lo Temp with Super Sandset	n/a	n/a	n/a
		Angular to round sand, low to medium strength	Texas Sand, Colorado Sand, etc.	n/a	n/a	n/a	n/a
	MEDIUM 100 - 6000 psi	Good to best quality round sand, fair to good strength to 4000 psi	Texas Sand or Ottawa Sand	n/a	n/a	n/a	n/a
		Curable resin-coated sand, good strength, high quality, prevents flowback.	n/a	Super Sand with Super Sandset	n/a	n/a	n/a
MEDIUM 130-225°F	LOW 1000 - 6000 psi	Good to best quality round sand, fair to good strength to 4000 psi.	Texas Sand or Ottawa Sand	n/a	n/a	n/a	n/a
		Curable resin-coated sand, good strength, high quality, lowest specific gravity, prevents flowback	n/a	Super Sand X Super Sand	AcFrac CR2 AcFrac CR	n/a	n/a
		Good strength, high quality, low specific gravity	n/a	Tempered Super-Sand X Tempered Super Sand	AcFrac PR2 AcFrac PR	Carbo-Lite	n/a
	MEDIUM 5000 - 8000 psi	Curable resin-coated proppant, good strength, high quality, lowest specific gravity, prevents flowback	n/a	Super Sand Super HS	Acme CR	n/a	n/a
		Good strength, high quality, low specific gravity, round proppant	n/a	Tempered Super Sand	Acme PR	Carbo-Lite	n/a
	HIGH 6000 or more psi	Curable resin-coated proppant, high strength, high quality, prevents flowback.	n/a	Super HS Super Sand Resin-Coated Ceramic	CR Resin-Coated Ceramic	n/a	n/a
		High strength, high quality, round proppant.	n/a	Tempered Super Sand	Acme PR	Carbo-Prop Sintered Bauxite	Interprop
HIGH 225-600°F	MEDIUM 4000 - 7000 psi	Curable resin-coated proppant, good strength, high quality, lowest specific gravity, prevents flowback.	n/a	Super Sand X Super Sand Super HS	AcFrac CR2 AcFrac CR	n/a	n/a
		Good to high strength, high quality, low specific gravity, round proppant	n/a	Tempered Super-Sand X Tempered Super Sand	AcFrac PR2 AcFrac PR	Carbo-Lite	n/a
	HIGH 7000 or more psi	Curable resin-coated proppant, high strength, high quality, prevents flowback.	n/a	Super HS Super Sand Resin-Coated Ceramic	CR Resin-Coated Ceramic	n/a	n/a
		High strength, high quality, high specific gravity, round proppant.	n/a	Tempered Resin-Coated Ceramic	PR Resin-Coated Ceramic	Carbo-Prop Sintered Bauxite	Interprop

Table 5
Hydraulic Fracturing Proppant Classes
and Sub-classes

CLASS	SUB-CLASS
Sand	Premium - Ottawa type sands from several deposits Standard - Texas Hickory sands from several deposits Sub-Standard - Colorado sands from several deposits Angular - Tuscaloosa sand used only in shallow formations
Resin Coated Sands	High strength-double coating; inner coat is tempered or precured for strength, outer coat is curable to bond particles together (Super HS) Curable coating-bonds together in formation with either temperature or chemicals (Super Sand or AcFrac CR) Tempered or precured coating-resin cure is advanced so it provides greater strength and crush resistance (Tempered Super Sand or AcFrac PR) Curable coating-on angular sand for shallow, low temperature formations; bonds together with temperature or chemicals (Super Lo Temp) Minimum resin coating-curable (Super Sand X or AcFrac PR2) Minimum resin coating-tempered or precured (Tempered Super Sand X or AcFrac PR2)
Ceramics	Sintered bauxite-high density, high strength ceramic particle, specific gravity 3.6 to 3.8 (Sintered Bauxite or Duraprop) Intermediate density ceramic-intermediate density, high strength ceramic particle, specific gravity 3.1 to 3.2 (Interprop or Carboprop) Low density ceramic-low density, intermediate strength ceramic particle, specific gravity 2.7 (Carbolite)

Table 6
Mesh Size and Proppant
Diameter Relationship

US SERIES MESH SIZE	PARTICLE DIAMETER (in)
8	0.0937
12	0.0661
16	0.0469
20	0.0331
30	0.0232
40	0.0165
50	0.0117
60	0.0098
70	0.0083
100	0.0059

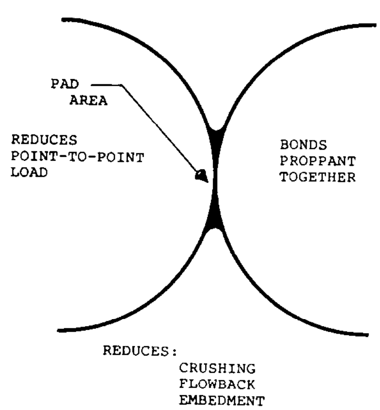

Figure 1—Contact area between resin coated proppants

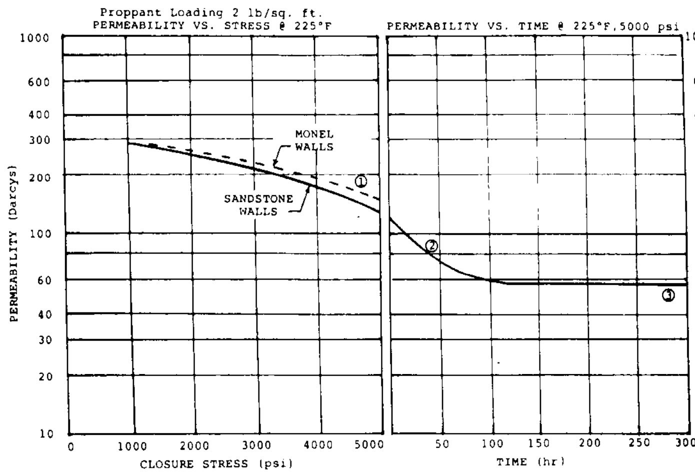

Figure 2—Long term permeability test on Ottawa type 20/40 sand

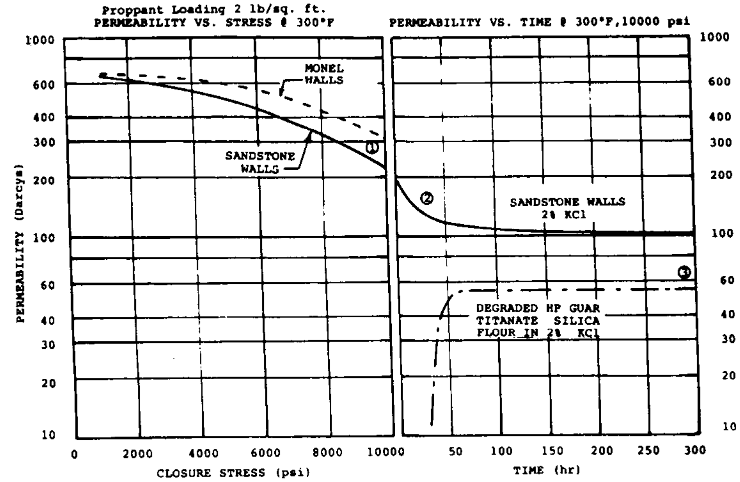

Figure 3—Long term permeability test on 20/40 mesh ceramic proppant

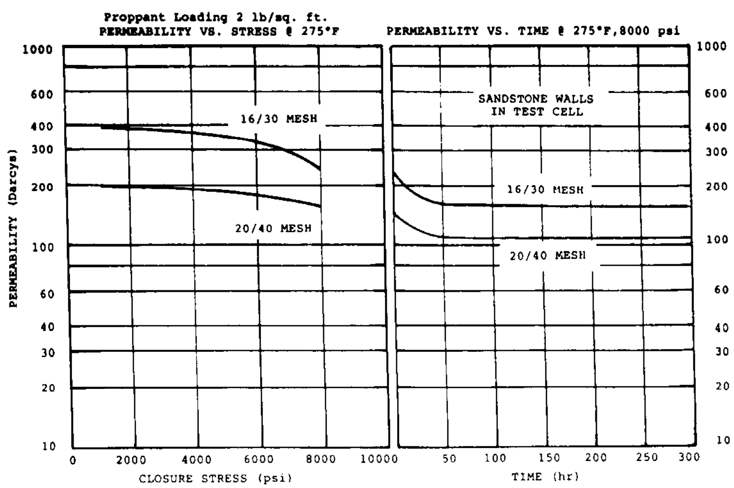

Figure 4—Long term permeability tests on double resin-coated (high strength) sand

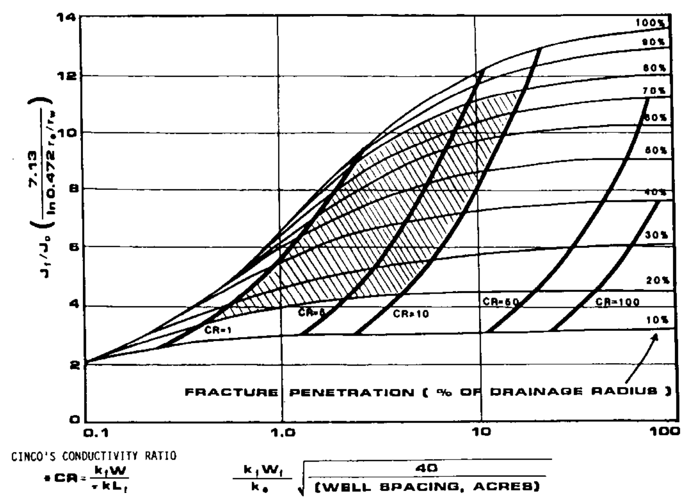

Figure 5—Comparison of dimensionless conductivity (CR*) with McGuire and Sikora PI curve