CONTROLLING PROPPANT FLOWBACK TO MAINTAIN FRACTURE CONDUCTIVITY AND MINIMIZE WORKOVERS—LESSONS LEARNED FROM 1,500 FRACTURING TREATMENTS

Jim M. Trela, Philip D. Nguyen and Billy R. Smith
Halliburton

ABSTRACT

The use of curable resin precoated proppants was often applied in the Permian Basin to control proppant flowback. However, these precoated proppant materials continued to allow proppant to produce back, especially during production surges because they did not provide sufficient consolidation strength to handle high drawdown. Since early 2005, a low-temperature curable liquid resin system has been selected to treat the proppant on-the-fly mainly during the tail-in stages in most of 1,500 hydraulic fracturing treatments. This paper highlights how the proppant back-production problems were successfully overcome through the application of this curable resin system. Detailed descriptions of the treatments, challenges, and lessons learned during the course of these fracturing treatments are presented.

Evaluation of these treatments has revealed that an optimum concentration of resin coating maximizes bonding between proppant grains and the consolidation strength of the coated proppant pack, locking the grains in place while minimizing any reduction of conductivity. Field results indicate that application of on-the-fly resin coating treatments effectively stops proppant flowback while allowing production rates to be maintained as designed. These treatments have drastically decreased the number of workovers for treated wells compared to those treated with resin precoated proppant or without resin treatments. This resin treatment process provides an economical means for controlling proppant flowback in wells with marginal reserves.

INTRODUCTION/BACKGROUND

Permian Basin

The Permian Basin is a large oil and natural gas producing area that is part of the mid-continent oil producing area. It is so named because it has one of the world's thickest deposits of rock from the Permian geologic period. It reaches from south of Lubbock, Texas to south of Midland and Odessa, Texas and extends westward into the southeastern part of New Mexico. The Permian Basin comprises several component basins: of these, Midland Basin is the largest, Delaware Basin is the second largest, and Marfa Basin is the smallest (**Fig. 1**). The Permian Basin extends beneath an area approximately 250 miles wide and 300 miles long

The Permian Basin is now in a mature stage of exploration and development. Production per well ranges from 5 to 200 BOPD, water production from 100 to 2,000 BWPD, and gas production from 0.10 to 2 MMscf/D. Although most of the wells were completed in sandstone formations, other formations include carbonates, dolomites, chalks, shales, and formations laminated with one or more of these materials. The rock formations are considered mostly competent formations; however, in some rare cases, weakly consolidated or unconsolidated formation materials are produced back during well production.

Proppant Flowback

Proppant flowback in the Permian Basin has been a problem in hydraulic fracturing treatments for many years. As proppant produces out of the fractures along with the produced fluids, fracture conductivity diminishes with time as the fracture width decreases. This choking effect causes the potential production of the well to decline. If the produced proppant remains in the wellbore, it may cover the perforation interval, limiting the production flowpath into the wellbore. A well cleanup is often required to remove the unwanted proppant from the wellbore to re-establish production from the entire perforated interval.

If the proppant flows back to the surface, it can cause severe damage to downhole (e.g., bottomhole rod pumps or electrical submersible pumps) and surface equipment (e.g., chokes, pipelines, and storage facilities). In such an event, the operator faces several dilemmas, including reduced efficiency of the electrical submersible pumps (ESP), a costly maintenance operation, surface equipment repairs, and lost production resulting from the shut-in periods. Also, flowback of the proppant reduces the conductivity of the fracture and, consequently, production from the well.

Most operators have tried to minimize proppant flowback by pumping a resin-coated proppant (RCP) during the tail-in of the fracturing treatment. In late 2004 and early 2005, the suppliers of RCPs were having difficulties keeping up with the demands of these precoated materials. The operators decided to use on-the-fly coating liquid resin systems (LRS) as an alternative to conventional RCPs. Because LRS can be coated on any natural sands, either white or low-grade, or any types of man-made proppants at the well site, regardless of their mesh sizes, the operators in the Permian Basin continued to select this resin coating system as the preferred flowback control solution in subsequent years. Moreover, LRS can be tailored to meet the design requirements as part of the fracturing treatment. The resin coating is completely compatible with the fracturing carrier fluid and does not interfere with the fluid transport capability and/or its breaking. The resin coating provides high consolidation strength for the resulting proppant pack placed in the fractures to withstand the high drawdown pressures and the effects of stress cycling during production and shut-in of the well.

One of the main disadvantages of limited-entry perforation is the high velocity of fluid flowing through a limited number of perforations in the production interval. High enough shear force applied on the proppant pack will overcome the cohesion force that the proppant obtained from forming a stable pack under the confining stresses of fractured formations. As a result, proppant will continue to produce out until this high velocity production encounters a more stable proppant pack that can withstand the shear force.

Water injection is often applied to sweep the oil as part of the oil-enhanced recovery process in the Permian Basin. The amount of oil recovered is directly tied to the amount of water produced. Studies have shown that a small volume of a second phase can drastically increase the pressure drop down the propped fracture by up to an order of magnitude.[1] This infers that drag forces resulting from two-phase or multi-phase flow could be high enough to effectively destabilize the proppant pack and cause the proppant to flow back from propped fractures.

Closure stresses applied on proppant in the generated propped fractures are known to be low in the Permian Basin. Some RCPs have been specially formulated to consolidate only under high closure stress. Although this feature facilitates tubing cleanout after a premature screenout, it can lead to reduced strength development of the RCP pack with delayed or uneven closure of the formation. The confining stress acting on the proppant pack during the curing process is probably not uniform because of variations of the formation in-situ stress and the formation rock-mechanical properties. In addition, some formations may not completely close after treatments. It has been shown that some hydraulic fractures do not completely close during the first 24 hours after hydraulic-fracture stimulation treatments, especially in the case of low-permeability formations.[2]

FORMATION SAND AND PROPPANT FLOWBACK CONTROL

The following methods and materials have often been applied, particularly in the Permian Basin, to prevent or minimize production of proppant during production of the well.

Reducing Production Rate

A common procedure for stopping or reducing proppant flowback is to reduce the production rate until the well produces proppant-free. This method is probably the most convenient and economical, short-term solution to the proppant flowback problem because it allows the operator time to assess the situation and implement alternative solutions. However, the obvious drawback of this approach is the revenue loss that occurs when the well is not producing at its full potential.

Forced Closure

Forced fracture closure[3] is a technique used to close the fracture rapidly, trapping proppant in a uniform distribution. This technique can potentially eliminate proppant flowback because the stresses exerted by the closing fracture walls help hold the proppant in place. However, closure stress does not always hold proppants in place. Test results indicate that closure stress may actually contribute to flowback. Fracture closure stress is normally the mechanism relied upon to hold proppant in place. Unfortunately, many times it is not very effective and results in proppant flowback.[4]

Pumping Larger Proppant during Tail-in

To enhance the formation of a stable proppant pack at the perforations and help lock the proppant in place, larger proppant can be pumped during tail-in of the fracturing treatment. However, this practice has not been reliable because of the uncertainty in placement and the capability of the proppant pack to handle high flow velocity.

Resin Precoated Proppants

RCPs were one of the first solutions applied to the problem of proppant flowback.[5,6] The resin coatings around each grain require closure stress and heat to force contact and bonding reactions with one another. These reactions create a mass of permeable, consolidated proppant. However, the bonded grains do not always have adequate strength, and consequently, proppant flowback with RCPs has been documented.[5,6] Further discussion of RCP is provided in the following section.

Fibers and Deformable Particulate

Fibrous materials[7] and deformable particulate[8] have been used in recent years to control proppant flowback. These solid materials are mixed with the proppant and become an intimate part of the proppant pack. A network is created between the proppant and the fibrous strands. The main functions of the fibrous strands are to induce bridging at the perforations and allow solid-free fluid to flow through. The use of deformable particulate requires the application of closure stress on the proppant-deformable particulate so the particles will adhere to one another via inter-embedment. Without the closure stress, a stable pack cannot be established. Although these materials reduce proppant flowback, they do not eliminate the problem entirely and are usually accompanied by significant decreases in fracture conductivity.[9]

Surface Modification Agent

Surface modification agents (SMAs) are water- and oil-insoluble, resinous materials that provide cohesiveness between proppant grains and do not harden or cure under reservoir conditions. When these liquid additives are applied to proppant during a fracturing treatment, they render proppant grains very tacky. These materials help enhance fracture conductivity by creating proppant packs with up to 30% increased porosity and permeability.[10,4] Flowback studies conducted with SMA-coated proppants indicate that the coating renders proppant significantly more resistant to production; however, sufficient fluid-flow rates can initiate proppant flowback.

Mechanical Screens

The primary function of screens is to provide mechanical support to prevent the proppant or gravel placed in the screen/wellbore annulus from flowing back into the wellbore. The gravel and proppant act as the primary filter to prevent formation sand and fines production. Screens help keep the gravel or proppant in place to support the perforation tunnel and fracture and maintain a conductive path for production. The screens can become damaged from plugging, scale buildup, corrosion, or erosion caused by producing formation fines and sand.[11,12] The installation of sand screens restricts the wellbore diameter.

Frac-Pack Completion

Frac-pack completion is designed to access reservoirs with high-permeability formations by combining propped fractures to bypass near-wellbore damage and gravel packs to retain formation sand. Tip screenout helps generate short and thick proppant-packed fractures toward the wellbore. A tip screenout is achieved when proppant at the leading edge of the fracture stops moving and, therefore, prevents further fracture extension. The annulus between the wellbore wall and the sand screen is tightly packed to maximize connectivity with propped fractures and to prevent development of void spaces. The width of the fracture is further increased by continued injection of the fracture fluid, providing an increased proppant packing inside the fracture. Propped-fracture operations that use sand-control screens have been successful in frac-pack treatments. However, screens employed in these applications increase well completion costs and are known to fail with time.[11,12] In case a refracturing treatment is required, the screen may need to be removed or the producing intervals may require reperforating before the re-completion can be performed.

GENERAL DIFFERENCES BETWEEN RCP AND LRS

Curable RCP was introduced to the industry during the 1980s as a means to prevent proppant flowback. RCP systems involve precoating the proppant in a manufacturing plant and partially curing the resin so that it can be conveniently stored and transported to the wellsite without consolidating. Several of the curable RCPs have partially precured coatings of phenolic resins. At the wellsite, these precoated proppants are handled as bulk sand, and operators use conventional equipment to mix the proppants with fracturing fluid and pump the slurry mixtures downhole. A major difference between RCPs and LRSs is that only a small fraction of the resin in RCP systems is curable, while all the resin in LRSs is curable. Consequently, LRSs can develop high strengths with less resin. Another major difference between LRSs and RCP systems is that the former are formulated for specific operations and, therefore, are specifically tailored for both low- and high-temperature applications.

The main advantage of RCP systems is their ready-for-use applications like those of uncoated sand or proppant. However, RCPs have the following disadvantages:

- Short shelf-life during warehouse storage.
- Activator must be used to initiate curing of the resin if the well has low BHT.
- Closure stress must be applied on the proppant grains to enhance the bonding between grains.
- Does not handle the effect of stress cycling as part of well operations.
- Only selected sizes of proppant are delivered to the wellsite.

LRS—Early and New Versions

As with any technology, the development of the LRSs has undergone various phases that often involved laboratory and field testing. Laboratory testing represents ideal conditions, while field trials help expose the difficulties that a resin system must overcome to meet the requirements of field applications.

In the 1980s and 1990s, the preparation of an on-the-fly LRS literally involved mixing multiple components at the wellsite just before the fracturing treatment. All components were either premeasured or measured at the wellsite.[13-15] It was not simple to re-adjust the resin treatment volume required for the fracture treatment design (i.e., treatment size, amount of proppant). Excluding a single component could lead to failure of the treated proppant pack to consolidate. Because both resin and hardener components were premixed into a single component and stored in a container, the resultant resin mixture had a short shelf life and was required to be utilized in coating as soon as possible before the resin viscosity increased to the extent that it could not be pumped and metered. If a premature screenout occurred during the fracturing treatment, the remaining mixed resin had to be disposed of properly. This mixed resin could not be saved for another fracturing treatment because of safety requirements and its limited shelf life.

The coating of this early version of LRSs involved metering the resin mixture directly into the frac-blender tub in which the resin interacted with fracturing carrier fluid before coating onto the proppant. This coating process is known as “wet coating.” Surface chemistry must be “just right” to ensure effective coating of the resin onto the proppant grains. Both the carrier fluid and coating agent are in competition to wet the proppant. If the balance is not correct, the following problems can develop:

- A less effective coating of the LRS is placed on the proppant as it competes with the carrier fluid, and/or poorer-than-predicted consolidation performance properties are achieved.
- Direct interaction of the coating agent with the carrier fluid may affect transport properties of the carrier fluid, such as its crosslinking and breaking times.

Since 2001, a new LRS and a new coating process have been developed to overcome these problems.[16] This LRS comprises a liquid resin and a hardening agent, which are preblended and delivered to the wellsite in separate containers. As long as these two components remain separate and uncontaminated, they have a long shelf life of several months.

The new coating process involves direct coating of proppant with the mixed resin during the transfer of the proppant from its storage container into the carrier fluid. Coating of the mixed resin onto the proppant is completed before the addition of the proppant to the gel carrier fluid. Therefore, the gel cannot compete to coat the proppant because the resin coating is already in place. This leads to more consistent properties from the coating agent and helps eliminate the possibility that an excess amount of coating agent is carried in the well. While this LRS can still affect the breaker and crosslinker performance, the effects are far less severe than in the earlier “wet coating” process.

The LRS was designed to handle the wide range of bottomhole static temperatures (BHST) in the wells of the Permian Basin. It was formulated with a proprietary additive to help with the removal of crosslinked gel coating on the proppant to enhance the contact between proppant grains, thus increasing the consolidation of the proppant pack even without applied closure stress. As a result, even under low or no closure-stress conditions, high consolidation strength of the coated proppant pack can still be developed. In addition to the ability to provide consolidation strength, this resin is also formulated to provide elasticity, which is beneficial to effectively handling the repeated stress-strain cycles that occur during normal production operations.

Fig. 2 shows the coating of LRS on 20/40-mesh Brady sand after the coated proppant was cured and removed from the pack chamber for consolidation measurement. The capillary pressure between grains pulls the liquid resin to the contact points, thus helping prevent resin from occupying the pore spaces. The bonding between grains, illustrated by the footprints (Fig. 2) at the contact points, helps establish the consolidation strength of the proppant pack to withstand stress load or high shear (**Fig. 3**). This consolidation strength (i.e., unconfined compressive strength) is proportional to the concentration of LRS coated on the proppant (**Fig. 4**). The consolidation strength of the proppant pack is dependent on the fluid/proppant system, proppant size, curing temperature, curing time, and resin concentration coated onto the proppant. Flow experiments have shown that this coating concentration of LRS provides sufficiently high consolidation strength to handle high flow rates (**Table 1, Fig. 5**).

Conductivity testing performed in the laboratory using modified API linear flow cells shows that coating LRS on 20/40-mesh, high-strength ceramic proppant actually improves the conductivity of the proppant pack (**Fig. 6**). Several factors contributed to this increase in conductivity. The tackiness of LRS coating alters the proppant pack density by increasing inter-grain friction, thus providing higher porosity within the pack. LRS not only bonds the proppant grains to each other, but also bonds to the fracture faces. This bonding distributes the point-source load of the proppant across the formation face, thus reducing the spalling effect and the formation fines intruding into the proppant pack.

FIELD IMPLEMENTATION

The wells were drilled in more than 40 formations ranging in depth from 1,400 to 16,000 ft, with BHSTs from 90 to 250°F. Depending on the operator and formations, well drilling spacing ranged from 160- down to 10-acre infill drilling. Approximately 95% of the wellbores at perforated intervals of the fracture-treated wells were vertical or slightly deviated, and approximately 5% were horizontal.

The objectives of the fracturing treatments performed in the Permian Basin included bypassing near-wellbore damage, enhancing wellbore communication with as many pay intervals as possible, and increasing and/or maintaining well productivity. Because of the possibility of proppant flowback in the area and marginal reserves, the operators decided to complete the wells using conventional hydraulic fracturing treatments in which the on-the-fly coating of curable liquid resin on the proppant was applied during the tail-in proppant stages of the treatment to help lock the proppant in place.

Fig. 7 provides a schematic layout of equipment involved during the fracturing treatment and coating of the LRS on the proppant.

Treatment Design

The majority of the fracturing treatments were performed in either sandstone or dolomite formations, but other formations such as limestone and shale were also included. A breakdown of these formations based on the total number of treatments is provided in **Fig. 8**. The main fracturing treatment was preceded by a breakdown test and an acid ballout. Both step-rate tests and mini-fracturing treatments were rarely performed because the fracture initiation pressure, fluid efficiency, and closure stress information were often obtained from wells that had been previously treated in the same field.

Nearly 80% of the fracturing treatments were performed as a single treatment per well. However, the other 20% were performed with multi-stage (2 or more) treatments per well on the same day.

The fracturing carrier fluid was designed for BHSTs ranging from 90 to 250°F, including mostly borate crosslinked hydroxypropyl guar, CO_2 foam of zirconate crosslinked carboxymethylhydroxypropyl guar, and occasionally with just linear gel. **Fig. 9** shows the percentage of each carrier fluid system applied in the Permian Basin based on the total number of performed fracturing treatments. For viscosifying gel fluids, low gel loading was used to help minimize gel residue and maximize conductivity in the proppant pack. Liquid gel concentrate (LGC) was used extensively in preparing the fracturing carrier fluid for the fracturing treatments. These products are highly concentrated forms of the fully hydrated gel prepared in a manufacturing plant. In preparation of the fracturing fluid, the LGC is diluted with water. The advantage of using LGC is that it is easily mixed on location, which precludes such problems as formations of “fish eyes” that require filtering of the prepared gel to prevent formation damage.

The fracturing fluid was generally pumped down casing or tubing. The average pad size for the wells was between 15 and 50% of the total fluid volume. Pump rates applied in the fracturing treatments ranged from 15 bbl/min to more than 50 bbl/min; however, more than half of the fracturing treatments were performed with pump rates of 30 to 40 bbl/min. **Fig. 10** shows various ranges of pump rates that have been applied in the area based on the total number of fracture treatments.

Various proppant materials were pumped, including mostly natural sands (such as Brady and Ottawa) and sometimes man-made proppants (intermediate- or high-strength ceramics), with mesh sizes ranging from 20/40 to 8/16. **Figs. 11** and **12** show the percentages of sand or proppant types and their mesh sizes that have been used, respectively, based on the total number of performed fracturing treatments. The maximum proppant concentration varied depending on formation lithology and permeability up to 8 lb/gal, with an average proppant amount intended for placement into the fractures ranging from 500 to 2,000 sacks per fracturing treatment.

Application of LRSs

The main reason that the operators in the Permian Basin used RCP was flowback control. In late 2004 and early 2005, many operators in the Permian Basin switched from running RCPs to LRSs coated on Brady or Ottawa sand because RCP was unavailable. Wherever they pumped RCP, they switched to the LRS. Based on the experiences gained from earlier fracturing treatments using RCPs, only the tail-in portions of the proppant were treated with LRS. Typically, about 15 to 20% of proppant was treated with LRS at the tail-in stages for consolidating the proppant grains in most of the fracturing treatments. Some operators also decided to run the LRS on all of the proppant to control proppant flowback in the entire interval, especially in cases of long and multiple perforated intervals. The tail-in proppant stage was coated with the LRS using a concentration of 1.5 to 2% (volume by weight of proppant).

The liquid resin and the hardener were delivered to the well location in separate containers. They were metered in proportion with the desired fluid and proppant rate pumped during the treatment. These individual components were then pumped through a static mixer, which provided sufficient mixing to create a homogeneous activated resin blend (Fig. 7). The mixed LRS was then injected to the bottom of the sand screw, which had its bottom end installed inside the sand hopper (**Fig. 13**). The auger action of the sand screw helped spread the resin onto the dry proppant as it moved the proppant from the sand hopper to the blender tub. Once poured into the blender tub containing the fracturing fluid, the coated proppant was mixed with the fracturing fluid before the slurry mixture was pumped downhole. This direct coating maximized the coating effectiveness of resin onto the dry proppant and minimized the chemical interaction between the resin and the fracturing fluid.

An aggressive breaker schedule was applied to ensure that early gel breaking would allow the proppant grains to obtain grain-to-grain contact before the resin began to cure. The shut-in duration of the well after the fracturing treatment often depended on whether the operator wanted to apply forced closure. Without applying forced closure, the shut-in duration of the treated well was dependent on the well BHST, ranging from 4 to 48 hours to allow the coated resin to achieve near or complete curing before the well was flowed back.

Post-Treatment Results

At the current pace of fracturing activity, over 1,900 hydraulic fracturing treatments will have been pumped through 2007 by more than 50 operators using the LRS process in the Permian Basin. More than 75 million lb of proppant will have been coated with the liquid resin. Except for a few premature screenouts, more than 95% of the fracturing treatments were successfully performed as per design. **Fig. 14** provides a summary of the number of fracturing treatments and amounts of LRS-coated proppant applied per year in the Permian Basin since 2004. The 2007 numbers are the projected totals based on jobs pumped through Q3 of 2007. An interesting thing to note from Fig. 14 is the 2006 numbers vs. the 2007 numbers, which show a 20% increase in lb of proppant coated with LRS but 20% fewer fracturing treatments. More operators in the Permian Basin have seen the conductivity increase that LRS coating gives them and want to coat a higher percentage of the total proppant pumped.

The treatment applications of LRS-coated proppant have provided an excellent solution for proppant flowback problems compared to the use of RCPs or any other additives that have been applied in the area. LRS-coated proppant drastically reduces the number of wells with proppant flowback, allowing the operators to maintain the well production at high drawdown without losing production because of well shutdown and/or workovers. In fact, the number of workovers is significantly lowered in wells that have been treated with LRS compared to those treated with RCPs.

The following examples illustrate various applications of liquid resin in different areas of the Permian Basin:

A. An operator in southeastern New Mexico had typically pumped RCP in fracturing treatments into the Delaware sandstone formation. Formation fines were often produced with production fluids, and it was necessary to shut in the wells for cleanout once or twice a year as a result of in-fill. After switching to LRS, no pumps have been replaced on 25 wells.
B. Another operator in southeastern New Mexico has pumped LRS-coated proppant since its inception and has not had any issues with proppant or sand producing back in Delaware sandstone, Bone Springs sandstone, or Wolfcamp carbonate zones on more than 50 wells.
C. An operator in west Texas had been using RCP at the tail-in of the fracturing treatments in Yates sandstone. The operator wanted to enhance conductivity of the propped fractures by switching to 12/20- and 8/16-mesh Brady sand, but the RCP vendors did not typically coat the larger-mesh proppant. The operator decided to use the LRS to coat 12/20- and 8/16-mesh Brady sand and has had no flowback issues with more than 700 fracturing treatments.
D. Another operator in west Texas has fractured 77 wells in the San Andres dolomite zone using 25% tail-in RCP and 25% tail-in proppant coated with LRS. The production results can be seen in **Fig. 15**; a 39% higher production is observed on wells where LRS was pumped. This operator has seen no flowback issues.
E. Another operator in west Texas has fractured 50 wells in the San Andres dolomite zone using 100% LRS (42 wells) instead of 100% RCP (11 wells) in an openhole zone. Of the RCP wells, 36% had to be cleaned out sometime during the first year due to fill-in of the wellbore. Only 15% of the LRS wells had to be pulled during the first year due to fill-in of the wellbore.
F. Another operator in west Texas traditionally fractured the Canyon sandstone zone with a CO_2 frac and 20/40-mesh Ottawa sand. Some of the lower Canyon intervals had a high fracture gradient and the formation crushed the proppant, creating fines and narrowing the fracture width. After pumping LRS-coated sand on the tail-in of 20 lower Canyon zones, no fines were observed and the production was as good if not better than uncoated sand.

LESSONS LEARNED / RECOMMENDATIONS

Fracturing Fluid Compatibility with LRS-Coated Proppant

There are compatibility issues with RCP systems and LRSs. When combined with fracturing fluid, break time or other properties may change. In addition, bond strength on LRS coating can be affected. It is important that quality control tests are performed to determine this effect. These procedures are well established and involve mixing the fluids with the coated proppant in the laboratory and observing changes. As regards fracturing fluid, this observation would generally be to check for changes in viscosity and break time following mixing; for the coated proppant, it would be change in compressive strength.

QA/QC testing of LRS-coated proppant should be performed with the fracturing fluid that will be used in the fracturing treatment to ensure the crosslinking time and break time followed the fracturing treatment design and schedule. This usually involves adjusting the pH or crosslinker concentration of fracturing fluid. Because short crosslinking time is desirable during the tail-in stages of LRS-coated proppant to enhance grain-to-grain contact between resin-treated proppant grains, lower crosslinker concentration and higher breaker concentration are applied to achieve complete breaking of the crosslinked gel.

Early Screenout

It was the intention of the operator to prevent screenout from occurring, especially during coating of LRS with proppant in the tail-in stage. However, if the screenout occurred during the LRS-treating stage, forced closure was immediately applied to prevent coated proppant from being cured and forming a consolidated pack inside the wellbore. Cleaning out or reaming out of the consolidated pack inside the wellbore often required the use of a coiled tubing unit or workover rig, which would require additional time and add complexity to the operation.

The resin-coating process may raise some concerns should premature screenouts occur during the fracturing treatment and the proppant slurry settle inside the wellbore. In this case, the well is flowed back as soon as possible so that tubing will not be needed to clean out the wellbore. However, if the screenout occurs toward the end of the treatment, it is a desirable feature that helps ensure complete coverage of all perforations. When allowed to remain in the wellbore to semi-cure, the LRS-coated proppant pack can be cleaned out with tubing, preferably coupled with a drill bit or notched collar.

Forced Closure

A forced-closure method was applied to some of the fracturing treatments. Soon after the displacement stage was performed and after the treating iron was disassembled from the wellhead, the fracturing fluid was allowed to flow back. In most cases, the crosslinked fracturing fluid has not been completely broken. However, the principle behind the forced-closure method is to enhance the closure of opening fractures while the proppant is still being suspended in the fracturing fluid such that the fracture closure helps lock the proppant in place before it settles to the bottom of the fractures. This locking mechanism helps keep the fractures opened or “propped” instead of completely being closed as in the case of proppant settled to the low end of the fracture. Early flowback may help increase BHST to speed up the cure kinetic of coated proppant. In addition, the early flowback of fracturing fluid during forced-closure enhances the removal of gel residues, which are often thought to contribute to the conductivity reduction or permeability damage of proppant if allowed to remain too long inside the fracture.

To minimize the amount of proppant producing back during forced closure, concentration of breaker is increased by 50 to 100% of the normal amount during the tail-in stage. This increase in breaker concentration promotes the breakdown of the crosslinked polymer fluid to enhance the grain-to-grain contact of the LRS-coated proppant and minimize the drag force during flowback of forced closure, especially with crosslinked fluid. The LRS-coated proppant grains are tacky in aqueous-based fluid, thus their grain-to-grain contacts should help minimize their movement and flowback with the fracturing fluid, even though the curing of the LRS on the proppant has not been well established.

General recommendations for forced closure can be applied to wells treated with LRS. Other well conditions may exist that can affect the production of proppant during flowback. A slow flowback-rate scheme is established according to the following recommendations:

- First 2 hours, less than 1 bbl/min.
- Next 2 hours, up to 2 bbl/min.
- Next 2 hours, not over 3 bbl/min.

The following recommendations are applied if a more aggressive forced-closure flowback rate is required:

- Using field experience, determine the appropriate method for the well conditions.
- If proppant is typically produced on offset wells that have been forced closed, LRS-coated proppant will be produced during forced closure.
- LRS-coated proppant is commonly produced (usually in small amounts) during the initial well flowback (up to 2 weeks), but proppant production should subside as consolidation strength develops with time and temperature.
- Early proppant production is considered good because perforation “flow channels” are created.

In some cases, the operator may want to perform forced closure right after the fracturing treatment for a few hours to help enhance closure of the fractures and heat up the proppant pack. After this short shut-in period, the well is shut in again for several hours, ranging from 4 to 48 hours depending on the bottomhole temperature of the well, to allow the LRS-coated proppant to achieve a complete cure.

Coating Proppant with Low Resin Concentrations

Instead of facing extremely high shear forces resulting from high production flow rates often experienced in south Texas or the Middle East, well production flow rates in the Permian Basin are relatively low. Hence, the amount of resin required to establish sufficient consolidation strength to handle shear forces in these wells is about 1/2 to 2/3 that of the high flow rate area. In terms of resin concentration, a LRS concentration of 1.5 to 2% (vol/wt) was often applied in coating the proppant compared to a typical concentration of 3% as often required in other areas.

Shut-In Time for Curing

The well should be shut in after the fracturing treatment for at least 8 hours if the BHST of the well is 175°F or higher. A longer shut-in time is required if the BHST is less than 175°F. Insufficient shut-in time does not allow the resin-treated proppant pack to obtain sufficient consolidation strength to handle high production flow rates, especially for the wells with a limited number of perforations.

An aggressive breaker schedule is recommended. The gel should be broken as quickly as possible to allow the proppant grains to obtain grain-to-grain contact before the resin hardens. If the gel is not broken before the resin hardens, the compressive strength of the pack will be very low. A forced-closure type breaker schedule or a ramped breaker schedule should be used. A general flowback recommendation is to begin flowback after the shut-in time at less than 1 bbl/min for the first few hours and then ramp up to the desired flow rate. However, well/reservoir conditions for each well will need to be reviewed to determine an appropriate flowback rate.

Equipment Cleanup after Treatment

Following treatment, cleanup solution was circulated through equipment that might have had direct contact with the LRS, including sand screws, frac-blender tub, pumps, and hoses, to prevent resin residue from setting inside this equipment. This cleaning helps ensure proper functioning for the next fracturing treatment.

CONCLUSIONS

Based on the lessons learned and results obtained from the fracturing treatments performed since 2004, the following conclusions have been made:

- With careful planning, LRS can be efficiently combined with hydraulic fracturing treatment to coat any proppant during any of the proppant stages to transform this proppant into a consolidated, permeable, in-situ screen for controlling proppant flowback.
- Application of LRS provides an effective method of controlling flowback of proppant and formation particulate to maintain well production without disruption (i.e., workovers) caused by solid particulate production.
- Properly coating and curing of LRS onto proppant allows the consolidated proppant to handle the high drawdown and the effects of stress-strain cycles during well shut-in and production.
- LRS has been an economic alternative to RCP with the added benefit of enhanced conductivity, proppant consolidation, and flowback control.

ACKNOWLEDGMENTS

Copyright 2008 Society of Petroleum Engineers. SPE 112461 first presented at the 2008 SPE International Symposium and Exhibition on Formation Damage Control in Lafayette, Louisiana, 13-15 February 2008.

REFERENCES

1. Vincent, M.C., Pearson, C.M., and Kullman, J. 1999. Non-Darcy and Multiphase Flow in Propped Fractures: Case Histories Illustrate the Dramatic Effect on Well Productivity. Paper SPE 54630 presented at the SPE Western Regional Meeting, Anchorage, Alaska, 26–28 May.
2. Blauer, R.E. and Holcomb, D.L. 1997. The Detection, Simulation, and Reservoir Performance Impact of Slowly Closing Fractures. Paper SPE 37404 presented at the 1997 SPE Production Operations Symposium, Oklahoma City, Oklahoma 9–11 March.
3. Ely, J.W. 1996. Experience Proves Forced Fracture Closure Works. *World Oil* (January): 37-41.
4. Weaver, J., et al. 1999. Application of Surface-Modification Agent in Wells with High Flow Rates. Paper SPE 53923 presented at the Latin American and Caribbean Petroleum Engineering Conference, Caracas, Venezuela, 21–23 April.
5. Graham, J.W., et al. 1975. Method for Treating Subterranean Formation. US Patent No. 3,929,191.
6. Norman, L.R., Terracina, J.M., McCabe, M.A., and Nguyen, P.D. 1992. Application of Curable Resin-coated Proppants. *SPE Production Engineering* (November): 343–349. SPE 20640.
7. Card, R.J., Howard, P.R., and Feraud, J.P. 1995. A Novel Technology to Control Proppant Backproduction. *SPE Production and Facilities* (November): 271.
8. Stephenson, C.J., et al. 1999. Increased Resistance to Proppant Flowback by Adding Deformable Particles to Proppant Packs Tested in the Laboratory. Paper SPE 56593 presented at the Annual Technical Conference and Exhibition, Houston, Texas, 3–6 October.

9. Al-Ghurairi, F., et al. 2006. Results from a Field Trial Using New Additives for Fracture Conductivity Enhancement in a High-Gas Screenless Completion in the Jauf Reservoir, Saudi Arabia. Paper SPE 98088 presented at the SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, 15–17 February.

10. Nguyen, P.D., et al. 1998. Enhancing Fracture Conductivity through Surface Modification of Proppant. Paper SPE 39428 presented at the Formation Damage Control Conference, Lafayette, Louisiana, 18–19 February.

11. Asadi, M. and Penny, G.S. 2000. Sand Control Screen Plugging and Cleanup. Paper SPE 64413 presented at the Asia Pacific Oil & Gas Conference and Exhibition, Brisbane, Australia, 16–18 October.

12. Stanley, F.O., et al. 2000. Matrix Acidizing Horizontal Gravel-Packed Wells for Fines Damage Removal. Paper SPE 65519 presented at the SPE/Petroleum Society of CIM International Conference on Horizontal Well Technology, Calgary, Alberta, Canada, 6–8 November.

13. Murphey, J.R., et al. 1989. Proppant Flowback Control. Paper SPE 19769 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, 8–11 October.

14. Dewprashad, B.T., et al. 1993. A Method to Select Resin-Coated Proppants. Paper SPE 26523 presented at the SPE Annual Technical Conference and Exhibition, Houston, Texas, 3–6 October.

15. Dewprashad, B.T., et al. 1998. Consolidation for Screenless Completions and Proppant-Flowback Control in Hot Wells. Paper SPE 48874 presented at the SPE International Oil and Gas Conference and Exhibition, Beijing, China, 2–6 November.

16. Lolon, E.P., et al. 2004 The Significance of Non-Darcy and Multiphase Flow Effects in High-Rate, Frac-Pack Gas Completions. Paper SPE 90530 presented at the SPE Annual Technical Conference and Exhibition, Houston, Texas, 26–29 September.

17. Nguyen, P.D. and Weaver, J.D. 2003. Controlling Proppant Flowback in High-Temperature, High-Production Wells. Paper SPE 82215 presented at the SPE European Formation Damage Conference, The Hague, The Netherlands, 13–14 May.

18. Nguyen, P.D., et al. 1998. New Guidelines for Applying Curable Resin-Coated Proppants. Paper SPE 39582 presented at the SPE International Symposium on Formation Damage Control, Lafayette, Louisiana, 18–19 February.

Table 1
Effect of Consolidation Strengths of LRS-treated 20/40-Brady Sand Packs on Proppant Flowback as Tap Water Was Pumping through the Pack

UCS (psi)	Water Flow Rate per Perforation (BWPD)	Proppant Flowback
10	140*	Yes
80	>300	None
330	>300	None
1,100	>300	None

* Flow rate when proppant begins to produce out.

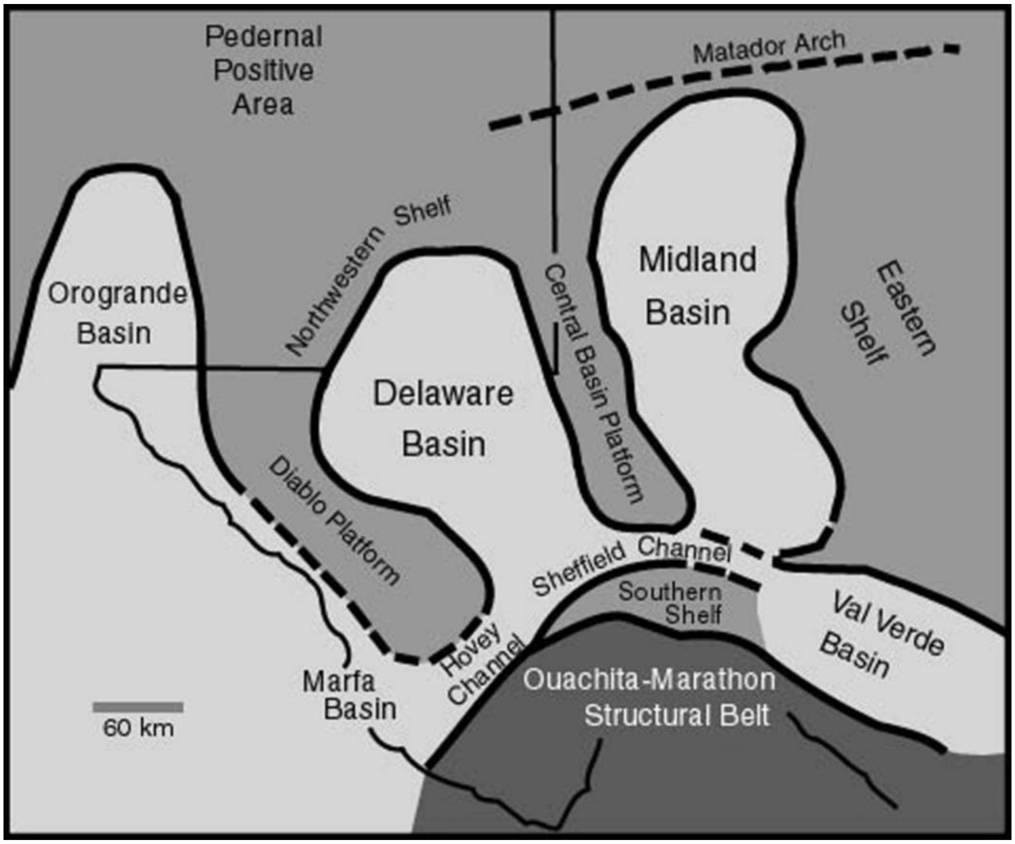

Figure 1—Paleogeographic setting of the Permian Basin during the Late Permian.

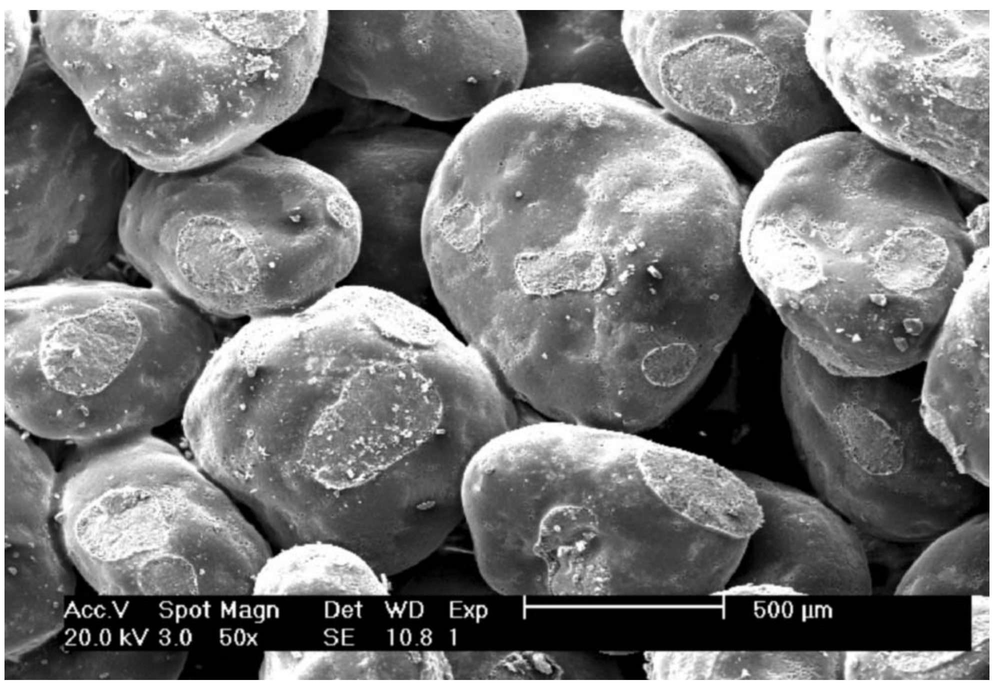

Figure 2—Photomicrograph (50X) of 20/40-mesh Brady sand that has been coated with LRS.

Figure 3—A simple test of LRS-coated sand pack after curing and obtaining sufficient consolidation strength to withstand stress loading.

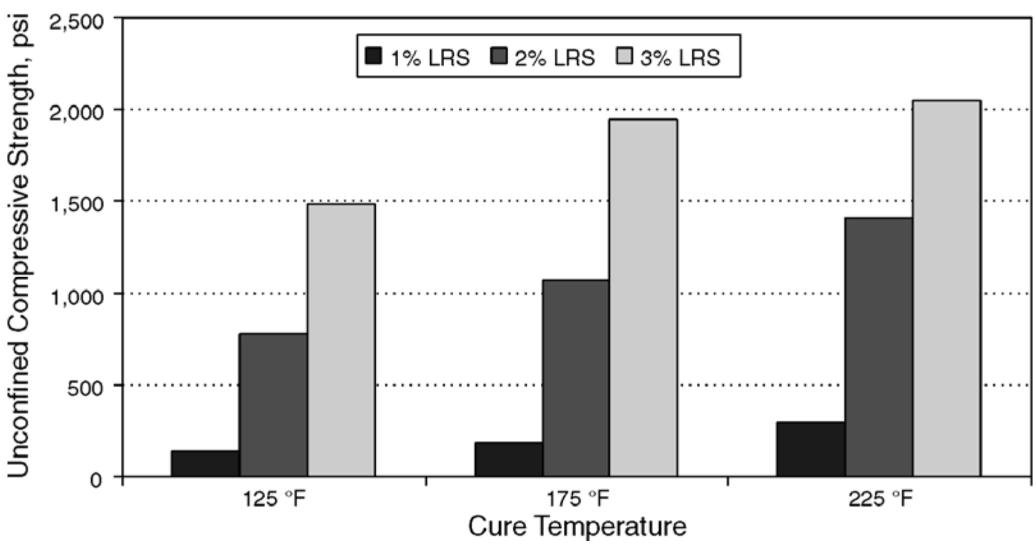

Figure 4—Unconfined compressive strength obtained for 20/40-mesh Brady sand coated with various LRS concentrations, mixed in linear HPG fracturing fluid, and cured at temperatures for 40 hours.

Figure 5—A flow cell was used in packing LRS-treated 20/40-Brady sand, curing at temperature, and pumping water through the pack at various flow rates to determine the resin performance in controlling flowback of the consolidated sand pack.

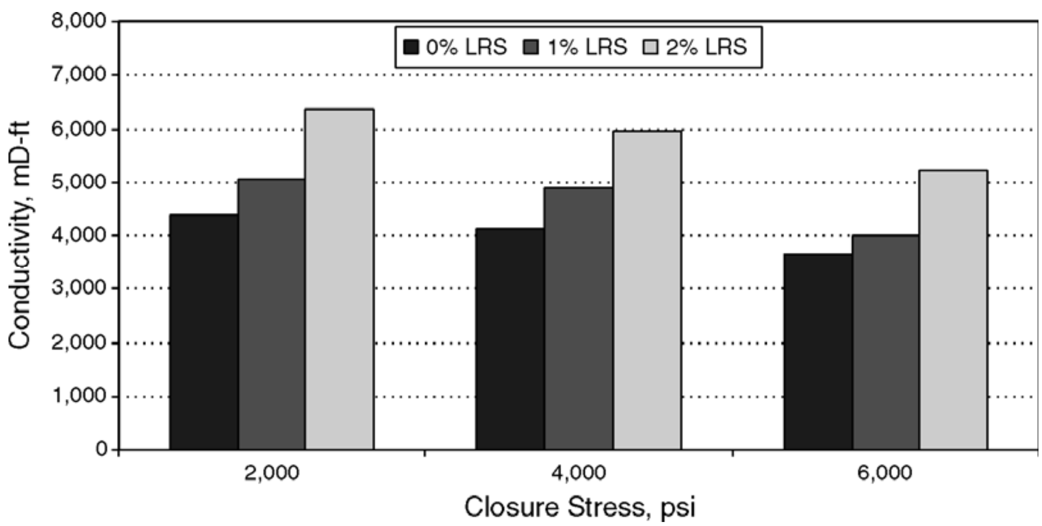

Figure 6—Conductivity values obtained at various closure stresses for 20/40-mesh, high-strength ceramic proppant, with various LRS concentrations.

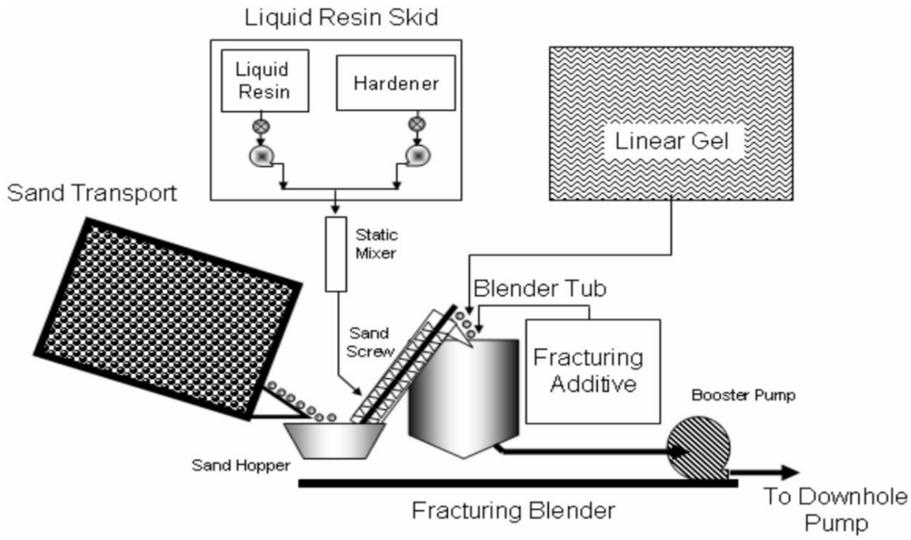

Figure 7—Fracturing equipment layout for the treatment using LRS to dry-coat proppant on the fly.

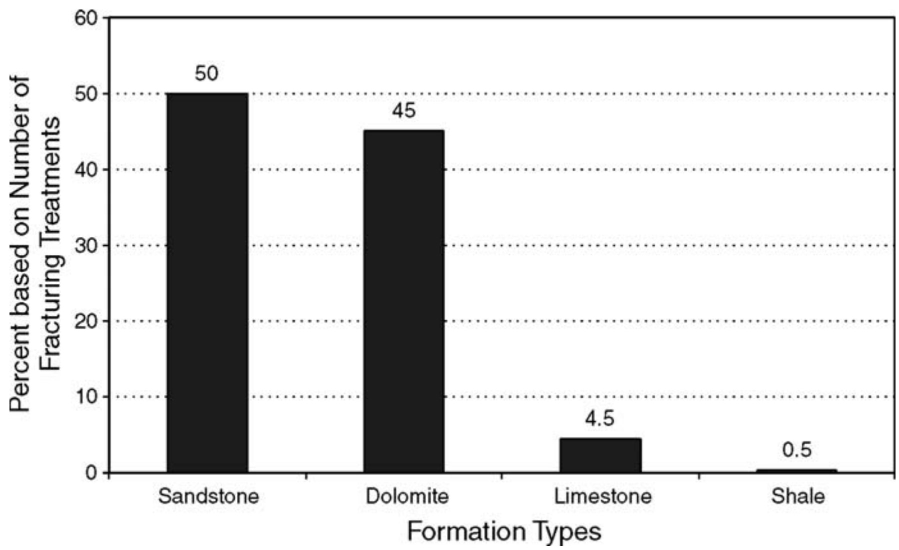

Figure 8—The types of formations that the fracturing treatments have been performed in based on the total number of treatments.

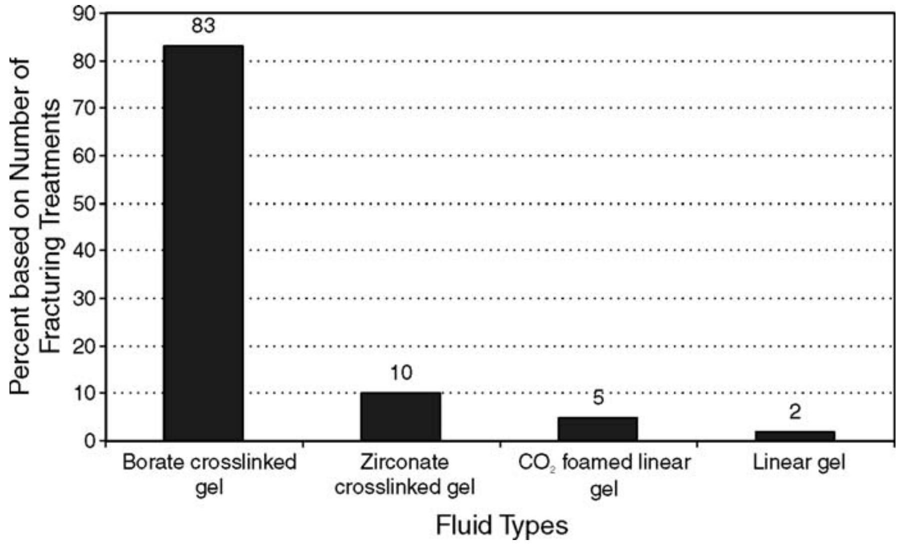

Figure 9—A breakdown of various fracturing carrier fluids applied in all the fracturing treatments.

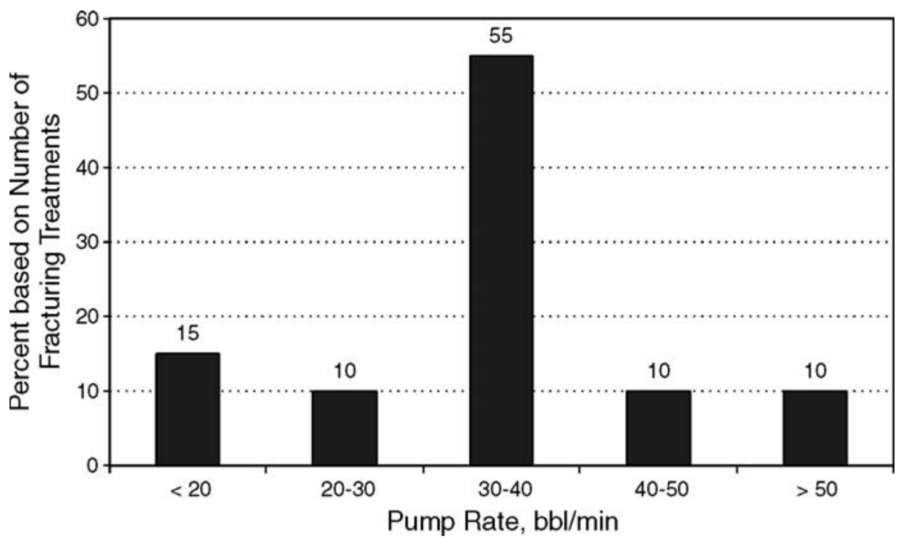

Figure 10—Ranges of pump rates applied in the fracturing treatments based on their total number of treatments.

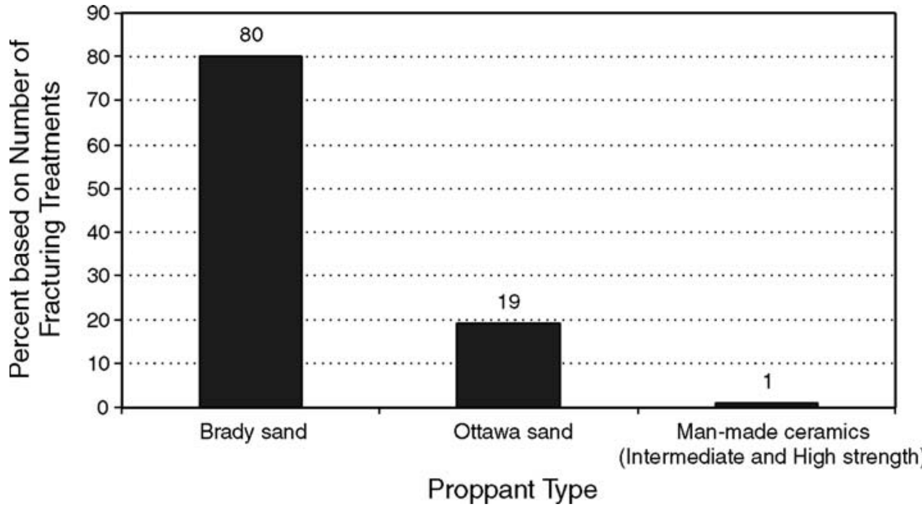

Figure 11—Amounts of proppant materials applied in fracturing treatments based on the total number of treatments.

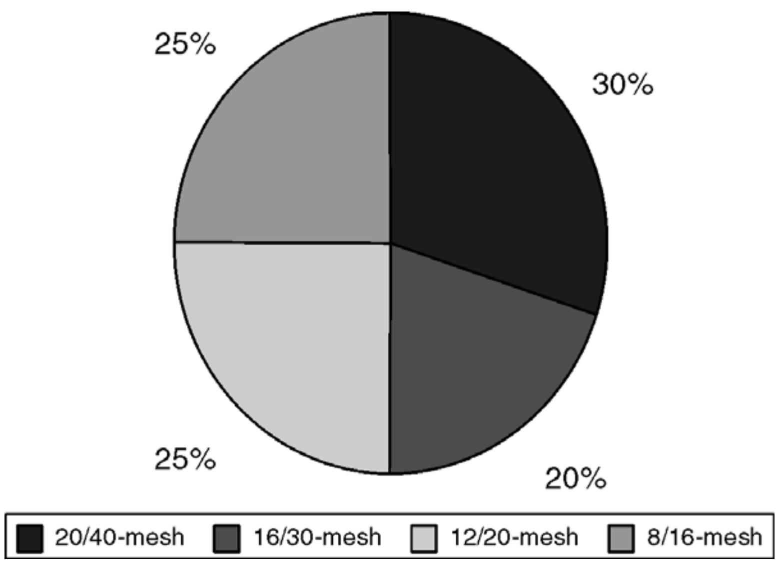

Figure 12—Portions of various proppant sizes used based on the total number of fracturing treatments.

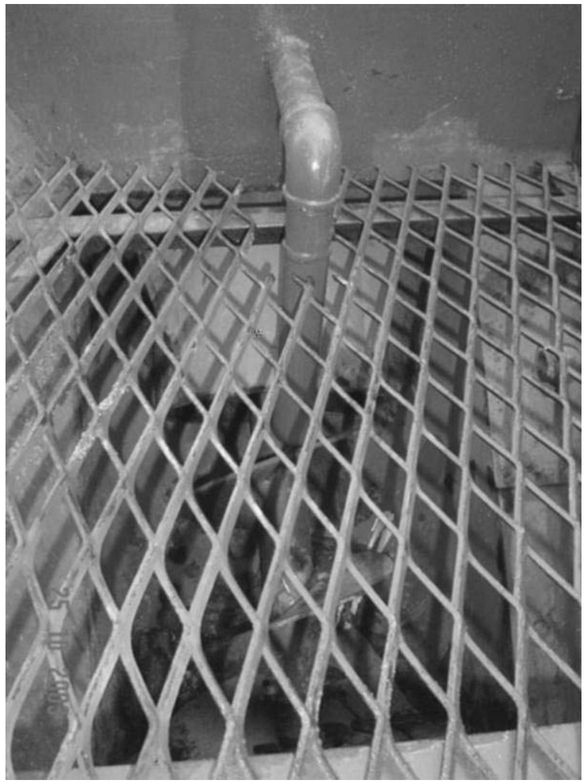

Figure 13—LRS is injected to the bottom of the sand screw as its auger action helps spread and coat the resin onto the proppant.

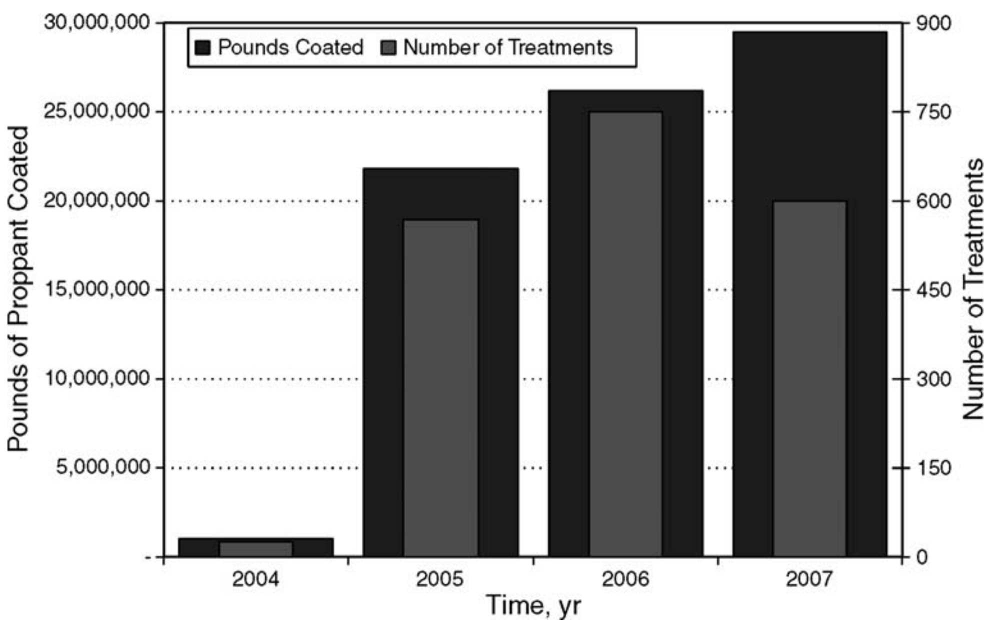

Figure 14—Amounts of sand/proppant coated with LRS and numbers of fracturing treatments performed since late 2004.

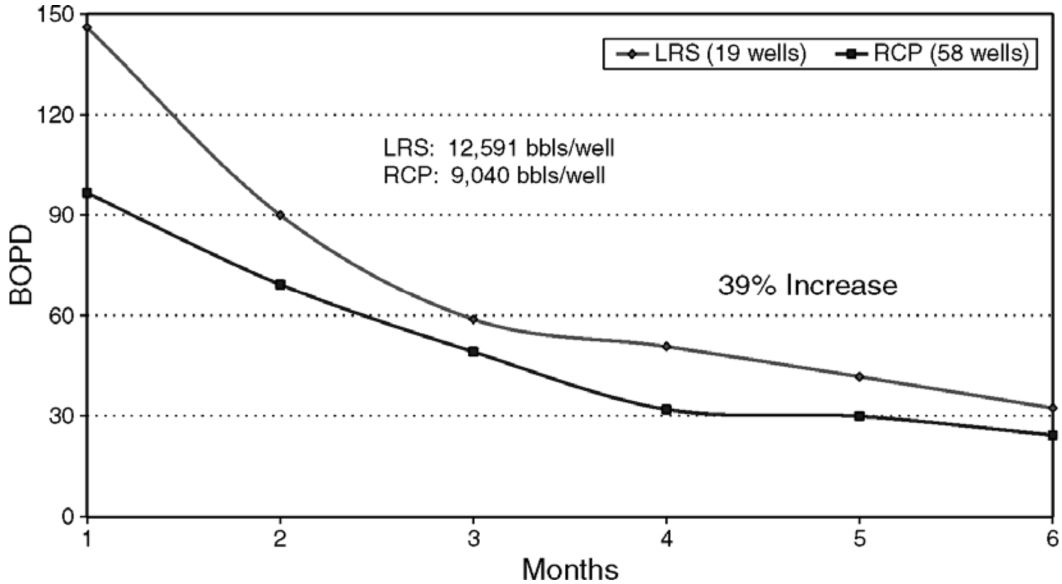

Figure 15—Production comparison on San Andres dolomite fracturing treatments using 25% tail-in proppant of RCP vs. 25% tail-in proppant coated with LRS.