REMEDIATION OF PRODUCTION LOSS DUE TO PROPPANT FLOWBACK THROUGH COILED-TUBING INTERVENTION

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ABSTRACT

This presentation discusses the results of experimental and field case studies of a remedial treatment technique designed to eliminate fracture proppant production. This process uses a low-viscosity consolidating agent, which is placed into the propped fractures via coiled tubing or conventional tubing coupled with a pressure-pulsing tool. The treatment fluids are designed to provide consolidation for previously placed proppant near the wellbore without damaging the permeability of the proppant pack. The consolidation treatment transforms the loosely packed proppant in the fractures and the formation sand close to the wellbore into a cohesive, consolidated, yet highly permeable pack.

Laboratory gas flow testing indicates that the proppant pack in a fracture model under closure stress required low-strength bonds between proppant grains to withstand high production flow rates. Field case histories are also presented to discuss treatment procedures, precautions, and recommendations for implementing the treatment process. One major advantage of this new remedial treatment technique is the ability to place the treatment fluid into the propped fractures, regardless of the number of perforation intervals and their lengths, without mechanical isolation between the intervals. The fluid placement efficiency of this process makes remediation economically feasible, especially in wells with marginally economic reserves.

INTRODUCTION

Many fracture-stimulated wells in the world today are subjected to curtailed production rates because of sustained proppant flowback problems. In fact, many wells are actually shut in because operators found them to be uneconomical to produce at subsequently lowered rates. Typically, production becomes restricted, such as by perforations being covered with produced proppant. The proppant produced during production often causes damage to downhole pumps and to surface equipment. In addition, repairing the equipment often results in costly downtime for the wells.

Low production rates directly affect potential revenue for the operator. Frequent workovers required for cleanup or sand removal, including shut-in time, also factor into the revenue losses caused by proppant flowback or sand infill. However, the problem will return and the loss of revenue will continue unless a treatment can be found that will remediate the problem at its source and not simply clean up the wellbore.

After an initial completion, it is often very difficult to conduct cost-effective remedial treatments to overcome proppant-production problems. Conventional remedial treatments are usually inadequate without some type of mechanical isolation technique. Conventional methods with a good chance of effective treatment are usually either too risky for well problems or too costly to consider for low-return reservoir conditions (or both).

Resin materials have also been applied to treat proppant flowback. However, a key problem with using these materials has been the inability to achieve a uniform placement of the resin into propped fractures for the entire perforated interval. This problem is amplified by the presence of variable permeability, perforation debris, formation damage in the near-wellbore region, and the high viscosity of many resin materials.

A system that attacks the problem at its source is a better approach to this problem. Using a system of treatment fluids placed precisely into propped fractures by coiled tubing can turn many marginal wells into excellent producers, and do so cost-effectively. The treatment chemicals introduced into the propped fracture will form a consolidated, highly permeable pack that can withstand the high drawdown associated with production. This paper discusses such a system.

WHAT CAUSES PROPPANT FLOWBACK?

In a number of in-depth studies for determining mechanisms that cause proppant flowback,[1,2] researchers found contradictions in numerical analyses of proppant flowback phenomena and field data. Despite broad coverage, literature on the subject neither provides a clear understanding of when to expect proppant flowback nor furnishes guidelines as to which proppant characteristics help prevent flowback. The following are known to contribute to proppant flowback:

- Flowback rate and fluid rheology.
- Formation closure stress and closure rate.
- Fracture face hardness and proppant embedment.
- Fracture height, width, and tortuosity.
- Proppant size, distribution, and angularity.
- Distribution of proppant within a fracture.
- Proppant binding forces.
- Perforation size, density, and orientation.

PROBLEMS OF PROPPANT FLOWBACK

As proppant produces out of the fractures along with the production fluid, fracture conductivity diminishes with time and closure stress as the fracture width decreases, creating a choking effect in the near-wellbore area, resulting in drastic production declines of the well. If proppant remains in the wellbore, it may cover the perforation interval, limiting the production flowpath to the wellbore. This process may require a well cleanup to remove the unwanted proppant from the wellbore to re-establish the flowpath for production. If the proppant flows back to the surface, it can potentially cause severe damage downhole (i.e., to bottomhole rod pumps, electrical submersible pumps [ESP], etc.) and to surface equipment (i.e., chokes, pipelines, storage facility). In such an event, the operator faces several dilemmas, including reduced efficiency of the ESP, a costly maintenance schedule, surface equipment repairs, and lost production resulting from shut-in.

PROPPANT FLOWBACK CONTROL IN PRIMARY COMPLETIONS

Frac Design. Advances in technology have yielded such tools as pseudo-3D design programs,[3,4] real-time job analyses,[3,4] and methods for improving quality control for fracturing fluids.[5] These measures enable engineers to achieve packed fractures through the proper design of treatments with tip screenouts. The potential for proppant flowback from a properly packed fracture is less than that for a fracture that is not properly packed, but efficient packing does not guarantee proppant-free production. Even well-designed and well-executed treatments have been reported to produce proppant.[6]

Forced Closure. Forced fracture closure[7] 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 just does not work very effectively, resulting in proppant flowback.

Mechanical Screens. Sand screens, including wire-wrapped screen or expandable screen, can be installed across the perforated interval to stop proppant flowback. In addition to installation of additional equipment in the wellbore, which may restrict the wellbore diameter, the screen may become damaged from fines plugging, scale buildup, or erosion caused by producing sand. In case a refracturing treatment is required, the screen may need to be removed or perforated to allow the refrac treatment to be performed.

Resin-Coated Proppants. Resin-coated proppants (RCPs) were one of the first solutions to the problem of proppant flowback.[8,9] The resin coatings around each grain react with one another, allowing the grains to bond. This reaction creates 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.[8,9]

Fibers and Thermoplastics. Proppant additives can help control or inhibit flowback. Solid additives, such as chopped fibers[10,11] or thermoplastic strips[12,13] build a network of grains with a mutual contact through a fiber or plastic strip, increasing the friction between individual grains and between the grains and the additive. These frictional forces increase the critical fluid production rate before pack failure occurs. Although these materials reduce proppant flowback, they do not eliminate the problem entirely and are usually accompanied by significant decreases in fracture conductivity.

Surface Modification Agents. 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 having up to 30% increased porosity and permeability.[14-15] 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.

All the additives mentioned are mainly applied during the primary fracturing treatment or refrac treatment. However, they cannot be used in solving the proppant flowback problems in existing wells.

COMMON REMEDIAL METHODS FOR PROPPANT FLOWBACK

Reducing Production Rate. A common procedure for stopping proppant flowback is to reduce the production rate until the well produces proppant-free. This method is probably the most convenient and economical means to solve the proppant flowback problem in the short term to allow the operator assessing the situation to implement alternative solutions. However, the obvious drawback of this approach is the loss in revenue that occurs when the well is not producing at its full potential.

Curable Resins. Injecting a curable resin into the perforated interval of propped fractures is the most common practice for remediating proppant flowback. It is often believed that the larger the injected volume of curable resin fluid, the higher the potential for success. However, field evidence has shown that this is not always the case.[16] Without proper placement technique, using large volumes of curable resin to treat a propped interval does not guarantee a successful treatment. This process can be expensive and may not produce economic results.

CURRENT PLACEMENT TECHNIQUES

Bullheading. Bullheading a treatment involves pumping the treating fluid into the wellbore without the use of zonal isolation tools or barrier devices and assuming that the fluid will be placed into the target area. The method can become less reliable, depending on the target interval, especially if the interval is long and contains multiple zones with varied permeabilities. The treatment fluid may mainly penetrate a single area, leaving other areas untreated, especially when multiple stages or fluids are required as part of the treatment procedure.

Jointed Pipe and Packers. Mechanical isolation devices or packers are combined with joined pipe to divide long wellbores into short intervals so that fluid placement into each interval may become more reliable (i.e., more uniform). The use of joined pipe and packers is complicated and time-consuming because it requires setting/unsetting of packers and movement from one zone to another. Generally, the shorter the interval is, the better the placement.

Coiled Tubing. Coiled tubing (CT) has been a valuable tool for well intervention operations for more than 15 years, including many fishing operations, workovers (wellbore cleanup, removal of in-fill, etc.) or chemical treatments (acid stimulation, water conformance, etc.). These operations include reciprocating of the tubing in the target area, either to help remove undesirable materials or to inject treatment fluid into the target zone.

NEW TREATMENT METHOD

A combination of new technologies enables application of the proppant treatment after it has been placed in the fracture. The new method involves using coiled tubing or jointed pipe coupled with a pressure-pulsing tool to enhance the placement of a consolidating treatment fluid into the near-wellbore region of propped fractures. This approach treats the existing proppant in the near-wellbore region to reduce or eliminate current and future proppant production and its related problems. The coating used in this new method does not produce the high consolidation strength commonly required of a coating in an initial fracturing treatment,[17] but laboratory and field testing results in this study have shown that effective coating can be achieved to lock the proppant into place. In addition, the treatment process clears fines and debris away from the proppant pack placed near the perforations to help restore and maintain conductivity between the fracture and the wellbore.

Pressure-Pulsing Tool. The pressure-pulsing tool is used in conjunction with CT and is based on patented fluid-oscillator technology. Fluid oscillation produces emissions of alternating bursts of fluid that create pulsating pressure waves within the wellbore and formation fluids. These pressure waves can break up many types of near-wellbore damage, helping restore and enhance the permeability of the perforations and near-wellbore area. The pressure waves expand spherically, providing 360° coverage while the tool is moved through the interval. As damage is removed, the fines are pushed farther away, and the waves penetrate deeper into the fractures and formations.[18]

Consolidating Systems. Current consolidating treatment fluids can be selected from one of the following liquid curable resin (LCR) systems, based on the bottomhole temperature of the well:

- A low-temperature epoxy-based resin designed for a temperature range of 70 to 225°F.
- A mid- to high-temperature epoxy-based resin designed for a temperature range of 200 to 300°F.
- A high-temperature furan-based resin designed for a temperature range of 275 to 550°F.

The materials are metered in on-the-fly and are injected downhole to coat the proppant existing in the fractures. Advanced chemical technology now allows the combination of the resin with the activator into a single component. This helps ensure that wherever the proppant pack is treated, consolidation will take place without the uncertainty often encountered with other consolidation systems that require external catalysts. Rather than an instant cure, as often occurs with acid catalysts, curing of the resins designed in these systems takes place slowly to allow complete placement of the resin into the proppant pack and complete displacement of the excess resin from the pore spaces within the pack to maximize its permeability.

The application of this consolidation system mainly involves the following steps:

1. Injecting a volume of preflush fluid for cleaning and conditioning the proppant pack.
2. Injecting a volume of low-viscosity LCR treatment fluid to coat the proppant and establish consolidation between grains.
3. Injecting a volume of post-flush fluid to displace the excess resin from occupying the pore spaces within the matrix of the proppant pack and minimizing the damage to the pack permeability.

Applying large volumes of curable resin with an ineffective placement technique will not provide a remedial solution to the proppant flowback problem. Selecting a suitable resin formulation and applying an appropriate placement method must go hand-in-hand to ensure the success of the treatment. **Fig. 1** provides an illustration of the volume of consolidating treatment fluid required for the treatment. The objective of this treatment is to treat the proppant near the wellbore and not the entire proppant pack in the fractures. The consolidating treatment fluid provides cohesion at the contact points between the proppant grains to keep them in place without causing damage or plugging in the pore spaces of the proppant matrix.

BENEFITS OF NEW METHOD

This new CT-deployed solution provides the following important benefits:

- Stabilizes the proppant pack in the near-wellbore region to help prevent further proppant production.
- Enables the well to be produced at higher rates.
- Minimizes subsequent cleanouts due to proppant fill in the wellbore.
- Reduces damage to artificial lift equipment such as electrical submersible pumps.
- Requires no mechanical isolation (i.e., packer).
- Requires limited footprints of equipment on location.
- Requires a limited number of operating crews during treatments.
- Is applicable for gas or oil wells, whether the formation is sensitive to water or not.
- Is economical because it is only essential that the proppant located near the wellbore be treated with consolidating fluid; therefore, only small volumes of treatment fluids are required.

LABORATORY EXPERIMENTS

Flowback Testing with Water. This system uses the same curable resin that was used in consolidating the formation sand[19] to obtain the based-line concentration. This resin material is then diluted with a proprietary diluent at various ratios to obtain a low-viscosity consolidating solution. The solution must be thick enough to penetrate the proppant pack and effectively coat the proppant grains but thin enough to penetrate the formation sand packing against the proppant pack without causing damage to the formation sand itself.

To illustrate the effectiveness in treating the LCR solutions onto the proppant packs, Brady sand with a particle size of 20/40-mesh was packed into brass flow cells. The flow cells have an inside diameter (ID) of 1.38 in. and a length of 5 in. Wire 60-mesh screen pieces were installed at the bottom and top of the sandpack. The sandpack was first saturated with kerosene to simulate a hydrocarbon source. The treatment of the sandpack involved injections of the following order of solutions:

1. Preflush solution containing 100 cc of a mutual solvent.
2. Preflush solution containing 50 cc of 5% NH_4Cl that includes 0.5% cationic surfactant.
3. Consolidating solution containing 100 cc low-temperature LCR solution.
4. Post-flush solution containing 150 cc of 5% NH_4Cl that includes 0.5% cationic surfactant.

After the treatment, the flow cells were placed in an oven at 175°F to allow the treated sandpack to be cured for 20 hours. After curing, the wire-mesh screen pieces were removed from both ends of the flow cell and a 0.5-in. port was installed at the exit end of the flow cell to simulate a perforation (**Fig. 2a**). Tap water flow was established by attaching a flowline from a progressive cavity pump to the entrance of the flow cell (**Fig. 2b**). The water flow rates were increased stepwise to determine whether the sandpack could remain stable and withstand the high shear force of the flow. A sand trap device prepared from an 80-mesh screen sieve was placed below the exit of water from the perforation to help detect and collect proppant grains that could be produced out with the flow of water.

After flow through the cells was performed, the stable sandpacks were removed from the cells and cut to size for unconfined compressive strength (UCS) measurements. **Table 1** summarizes the results of flow rates, amounts of proppant produced, and UCSs obtained for the sandpacks treated with various diluted LCR solutions.

The results indicate that an unconfined compressive strength of about 10 psi should be sufficient to withstand at least a water flow rate of 100 BPD per perforation. However, overly diluted consolidating solution did not provide sufficient consolidation strength for the proppant pack to handle comparable flow rates.

FLOWBACK TESTING WITH GAS

API Cell Setup. A modified API linear conductivity flow cell was used in this part of the study (**Fig. 3**). Brady sand with 20/40-mesh particle size was packed between two Ohio sandstone core wafers. The sand was packed with a loading concentration of 3 lb/ft^2 with 60-mesh screen pieces placed at entrance and exit ports (both ports had a 0.5-in. hole size). After installing under the press, the sandpack was saturated with 2% KCl, and a stress load of 2,000 psi was applied on the sandpack at a rate of 100 psi per minute. The system was allowed to equalize overnight at 175°F. The proppant pack width was determined by measuring the heights of the two pistons with a linear variable displacement transducer (LVDT). The LVDT is a measure of the change in width of the flow cell. If proppant is allowed to exit the test cell, the LVDT value will change.

A low-temperature, epoxy-based consolidating solution was selected for treating the sandpack. The order of the treatment fluids on the sandpack mainly included:

- Preflush solution containing 50 cc of mutual solvent.
- Preflush solution containing 25 cc of 5% NH_4Cl containing 0.5% cationic surfactant.
- Consolidating solution containing 50 cc of LCR solution.
- Post-flush solution containing 75 cc of 5% NH_4Cl containing 0.5% cationic surfactant.

After the consolidation treatment, the cell was shut in at 175°F for 20 hours to allow the treated sandpack to cure. After curing, a nitrogen gas line was attached to the entrance of the cell. Nitrogen gas simulating gas production entered the system through a mass flow controller. The gas then flowed through the heating vessel to boost its temperature to the test temperature before it entered the cell. The screen at the exit port was removed and a proppant-trapping device was attached to this port to capture the proppant produced out during flow of the nitrogen gas. **Fig. 4** provides a schematic layout of the equipment involved in this testing.

The gas rate was increased at 5 standard liters per min (sLm) increments to 100 sLm (which corresponded to a field equivalent flow rate of 25 MMscf/D through a fracture that is 100 ft in length) while the closure stress on the proppant pack was maintained at 2,000 psi. With the gas rate maintained at 100 sLm, the closure stress was decreased from 2,000 psi to 1,000 psi and then returned to 2,000 psi. This stress cycle was repeated two more times.

The gas rate was then increased to 300 sLm (i.e., 75 MMscf/D field equivalent flow rate) to determine whether the proppant pack would fail at this high gas rate. The proppant pack remained stable throughout the flow test, both at 100- and 300-sLm gas rates and during stress cycling (**Fig. 5**). The LVDT remained steady throughout the entire test duration, indicating that the pack width was held constant and no proppant was produced.

After flowing gas through the cell, the trapping device was removed from the exit port. **Fig. 6** shows a view of the pack through the 0.5-in. perforation at the exit port of the cell. After the cell was cooled down to room temperature, the entire sandpack and Ohio sandstone wafers were removed from the cell to be examined more closely. Scanning electron micrographs (SEM) of the sand grains at different locations along the pack show the footprints of contact points between grains with minimum blockage of resin occupying the pore space within the proppant pack (**Fig. 7**). In addition to SEM evaluation, the loss-on-ignition (LOI) analysis indicates the amount of resin treated on the proppant was uniform throughout the pack (**Table 2**).

A similar flowback test was performed for 20/40-mesh bauxite proppant using a mid- to high-temperature epoxy-based resin as the consolidating treatment fluid. The treated proppant pack was cured at 250°F for 20 hours. During flow with nitrogen gas, the stress cycle was started from 6,000 psi to 3,000 psi and returned to 6,000 psi three times (**Fig. 8**).

Another flowback test was performed for 20/40-mesh bauxite proppant using a high-temperature furan-based resin as the consolidating treatment fluid. The treated proppant pack was cured at 350°F for 20 hours. The stress cycle was started from 6,000 psi to 3,000 psi and returned to 6,000 psi three times during flow with nitrogen gas to simulate gas production (**Fig. 9**).

Both consolidating treatment systems were also found to successfully lock the proppant in place at 100-sLm and 300-sLm gas flow rates (or 25 and 75 MMscf/D respectively of equivalent field flow rates), even with the effect of stress cycling.

FIELD TESTING

Treatment Procedure. The chemical treating fluids used in this process, when properly deployed, offer no obstruction to the wellbore or completion and can be placed in multiple intervals in one treatment operation. The process is deployed as follows (**Fig. 10**):

1. The well is cleaned out and any fill is removed down to below the bottom-most producing interval.
2. A pressure pulsing tool is installed on the bottom of a typical CT (or jointed pipe) bottomhole assembly (BHA).
3. The CT is deployed into the well to the bottom-most producing interval.
4. A preflush displacement fluid is pumped through the pulsing tool and into the producing interval. This washes the proppant surface and prepares it to receive the LCR. The CT annulus is closed during this process (Fig. 10.1).
5. The BHA is moved upwards across each producing interval in the wellbore and the preflush treatment is repeated (Fig. 10.2).
6. Once at the top of all producing intervals, the LCR is pumped through the pulsing tool, directly adjacent to the producing interval being treated. The pulsing action is essential and necessary to aid in flushing away debris or fines in the pack and to help ensure proper distribution of the LCR (Fig. 10.3).
7. The CT is run back into the hole and the consolidation step is replicated at each producing interval to the bottom-most interval (Fig. 10.4).
8. Now at the bottom of the well again, a final post-flush fluid is displaced and injected through the pulsing tool and into the producing interval to remove excess LCR from plugging the pore spaces of the proppant pack (Fig. 10.5).
9. This process is repeated as the CT is withdrawn until it reaches the uppermost producing interval (Fig. 10.6).
10. The CT is removed from the well, with the CT annulus still closed (Fig. 10.7).
11. A cleanup solution is injected through the CT to clean and prevent the equipment from contamination with LCR residue.
12. The well remains shut-in for a period of time, depending on the bottomhole temperature of the well, from 2 to 48 hours.

Fig. 11 shows a schematic layout of equipment that may be involved during wellbore cleanup and remedial proppant treatment operations. These mainly include:

- Coiled tubing/pressure pulsing tool.
- Combo pump.
- Chemical skid.
- Static mixer.

One key feature for this type of operation that needs to be highlighted is the limited footprint for equipment as well as the small number of operating crews required at the wellsite.

CASE HISTORIES

Numerous wells were successfully treated using the method described in this study. Either a combination of coiled tubing and pressure-pulsing tool or jointed tubing and pressure-pulsing tool was used to ensure the effectiveness of placing the treatment fluids into the perforated intervals.

Case 1: South Texas. Two zones in the sandstone formation of the subject well were fractured separately in February 2006. Both zones were fractured with 20/40-mesh white sand coated with a curable resin. Their combined gas production was approximately 1.1 MMscf/D, 1,900 BWPD, and 1 cup to 1 gal of proppant per hr. Sand production caused problems with the surface equipment and flowback supervision costs were approximately US $1,800 per day or more.

The decision was made to isolate the zones, treat the top zone, and evaluate performance. The top zone had four perforated intervals of 22, 6, 8, and 8 ft from 11,066–11,136 ft with perforation density of 6 shots per ft (spf), a bottomhole temperature of 285°F, and an estimated bottomhole pressure of 9,000 psi. The production casing was 4 ½-in. 15.1 lbm/ft. The treatment was pumped down 1.25-in. CT and through a pressure pulsing tool at approximately 1-bbl/min injection rate. The treatment fluids consisted of preflushes (5 gal/ft), high-temperature furan-based consolidating resin solution (5 gal/ft), and post-flush (5 gal/ft), reciprocated across the four intervals. Final displacement after post-flushing was to top of perforations. The base fluid for the pre- and post-flushes was 3% KCl containing a 0.25% cationic surfactant.

The post-treatment production was approximately 700 Mscf/D of gas, 9 BOPD, 1,000 BWPD, and zero sand for the treated zone. Current plans include drilling up the bridge plug and producing the bottom zone. If this zone produces sand, it will be treated using a similar treatment system as that performed for the top zone.

Case 2: Argentina. An oilwell was fractured in October 2004 through four perforated intervals having a net interval of 66 ft. The well has a bottomhole temperature of 180°F and a bottomhole pressure of 3,129 psi at 8,202 ft MD. Lightweight ceramic proppant with a mesh size of 16/30 was used in the initial fracturing treatment. Initial oil production for this well was approximately 40 m^3/day with a water cut of 60 to 98%. The proppant continued to produce back after the fracturing treatment, which required three workovers to remove the proppant from the wellbore. Estimated cost for these workovers was around US $150,000. Pump efficiency was drastically reduced and oil production was decreased to 1 m^3/day.

The operator looked for a treatment process that could eliminate proppant flowback. In December 2005, the remedial treatment method described in this study was applied in this well. It involved the use of CT, a pressure pulsing tool, and a low-temperature LCR treating fluid system. The treatment fluid included preflushes (5 gal/ft), LCR (2.5 gal/ft), and post-flush (5 gal/ft). All of these fluids were commingled with nitrogen during placement because of low reservoir pressure. The liquid injection rate was 1 bbl/min and the N_2 gas rate was 800 scf/min.

After the remedial treatment, the proppant flowback problem was completely resolved. The oil production rate steadily returned to 10 m^3/day and increased while water cut maintained at around 80%.

Case 3: Arkansas. There have been four wells treated with this process in the Arkoma Basin. All the wells were originally fracture-stimulated around 2003 with 20/40-mesh white sand. An increase in initial gas production was witnessed post fracture in each well, but production diminished at a fast pace as a result of fracture sand production. Excessive frac sand production caused the efficiency of the rod pump system to drop, which lowered gas production and created costly workover completions and nonproductive time. The issue of sand production became so severe it required the operator to shut down production on more then one well in question. The wells required regular maintenance of a workover rig to clean out produced frac sand every week to 3 months at an average cost per cleanout ranging between US $18,000 to $44,000 depending on the necessity of nitrogen usage.

Consolidation treatments were performed on two zones on the same day (Wells 1 and 4), resulting in approximately 6 hours of on-location pumping, per well. A consolidating treatment volume of 75 gal was pumped between conditioning flushes. Each treatment was performed down 2 3/8-in. jointed tubing, using a local workover rig to reciprocate the tubing across each perforated interval. The consolidating treatment fluid was placed to the fracture sand using a pressure-pulsing tool, attached to the end of the jointed tubing.

Figs. 12a–12c show the gas production rate before and after the consolidating treatment using the new placement method (highlighted in red is the date of treatment). This process has shown immediate results in increasing natural gas production and eliminating maintenance cleanout workovers, the number of pump replacements, and the amount of maintenance expenditures. From treatment of the first two wells, the operator has saved $160,000–$440,000 per well in the first year post-treatment. Expected returns are as good or better for Wells 3 and 4, because of higher gas production rates compared to Wells 1 and 2. **Fig 12c** highlights in blue the extensive wellbore clean out history prior to the consolidation treatment highlighted in red. **Table 4** provides a detailed history of Well 2 activities.

Case 4: Oklahoma. A gas well located in Blaine County, Oklahoma had been fractured with resin-coated proppant (RCP). Following a production period in which proppant did not produce back, the well eventually began to produce proppant and formation sand as well as increased water, while the gas production rate declined. Large amounts of proppant and sand fill in the wellbore were choking off the perforated interval. After several workovers using CT to remove sand fill in the wellbore, the operator decided to shut in the well. A 2-step water- and sand-control treatment was performed to resolve these solids and water production problems.

The producing interval at 9,500 ft consisted of two perforated zones totaling 14 ft. The well had been fractured with 54,000 lb of RCP. Formation permeability was determined to be between 0.1 to 5 mD with a bottomhole temperature of 165°F. Coiled tubing with an attached pressure-pulsing tool was used to place 4,000 gal of a relative permeability modifier (RPM) polymer solution (water control treatment) and 50 gal of consolidating agent into the perforated intervals at an injection rate of 1 bbl/min. After the treatments, the well was shut in for 48 hours to help ensure (1) complete anchoring of the RPM polymer onto the formation sand surface and (2) curing of the consolidating agent between particulates. After the shut-in period, the well was allowed to flow back and began to produce.

The average water production rate before treatment was 325 BWPD (**Fig. 13a**). After treatment with the water/sand control system, this rate was reduced to 160 BWPD (**Fig. 13b**), more than a 50% decrease. No apparent flowback of proppant or formation sand was observed after the first two weeks following the treatment. Four weeks after the treatment, a check of plug back true depth (PBTD) using wireline indicated only 1 ft of solids in the wellbore. The operator plans to install a submersible pump in the wellbore to obtain desirable gas production flow rates.

RECOMMENDATIONS

Based on the case studies presented, it is recommended that the following guidelines be observed when applying the treatment described.

- Review the well parameters thoroughly and plan the treatment design to fit the need.
- Select the appropriate consolidating treatment fluids, including preflushes, consolidating agents, and post-flushes. In addition, determine the appropriate treating volumes.
- An LCR solution that can provide an unconfined compressive strength of at least 50 psi should be used in the remedial proppant treatment.
- Ensure that the preflush and post-flush fluids are compatible with the formations.
- Mix the resin components with a static mixer before injecting downhole.
- If jointed tubing and packer are used in fluid placement, ensure that the packer is unseated and pulled slowly to prevent swabbing of the treatment fluid from the propped fracture back into the wellbore.

CONCLUSIONS

A combination of coiled tubing, pressure pulsing tool, and advanced consolidating system provides a reliable and economical method for remedial proppant treatment to overcome proppant flowback problems. This method should be considered as part of any well cleanout operation. The technique offers the opportunity to eliminate subsequent cleanouts and improve the operator's return on investment due to associated cost savings.

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Table 1
Effect of Treating Diluted LCR Solutions on 20/40-Brady Sand Pack

Resin-Solvent Dilution Factor	Maximum Water Flow Rate per Perforation, BWPD	Proppant Flowback	UCS, psi
1:1	>300	None	1,100
1:2	>300	None	330
1:3	>300	None	80
1:5	140*	Yes	10
1:7	60*	Yes	~1

* Flow rate when proppant begins to produce out.

Table 2
LOI Values of Resin Coated on Sand Pack at Various Locations

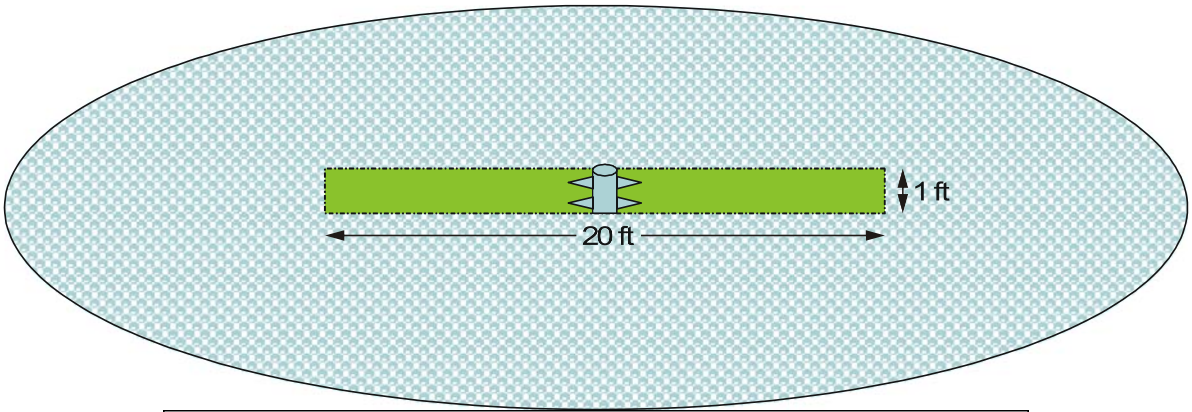
Sand Pack Position	LOI, %
Inlet	0.55
Middle	0.54
Outlet	0.57

Table 3
Arkansas Treatment Summary

		Well 1	Well 2	Well 3	Well 4
Casing	Size, in.	5.5	5.5	4.5	4.5
	Weight, lb	17	17	11.6	11.6
	Grade	J-55	J-55	J-55	K-55
Interval	Formation #1	Orr	Casey	Orr	Tackett
	Depth, ft	5703–5733	4760–4807	6782–6800	4964–4976
	Formation #2	Basal Atoka			Spiro
	Depth, ft	5750–5779			7490–7506

Table 4
Arkansas Well 2 History

Date	Comment
11/3/1986	Spud date.
Dec-96	Well completed.
1997-2003	Well produced naturally until 2003.
6/15/2003	Work order to remove packer and fracture the Casey Formation.
	First sand cleanout; cleaning out fill left from fracture treatment (4,708–4,878 ft).
	Flowed back & died.
	Cleaned out fill (4,777–4,881 ft) and landed tubing at 4,755 ft.
12/5/2003	Tagged TD at 4,787 ft wim. FTP 12 psi, FBHP 76 psi at 4,783 ft w/ light foam.
Jun–Aug 2004	Washed sand 4,747–4,884 ft. Set tubing on fill.
	Cleaned out sand several times to 4,884 ft by washing w/ foam air unit and by using tubing pump.
	Loaded tubing and pressure tested. Set pumping unit, pump not pumping.
	Pulled rods and pump; pump stuck on way out of hole. Finally pulled loose.
	Purchased new pump and TIH; loaded hole and pressure tested. Pump ran 2 hours and failed.
	Raised o/o tool and POOH w/ rods. TIH w/ tbg bailer to work sand bridge to 4,854 ft.
	TIH w/ tbg, pump & rods – pump ran all night and quit making water.
	POOH w/ rods & pump. Cut stuck tubing @ 4,808 ft and fished tubing.
	TIH w/ bit and washed sand 4,820–4,878 ft and POOH. TIH with notched collar.
	Pumped 300 gallons sulfamic acid down tubing and flushed with 10 bbl KCl water.
	TIH with pump and rods; pumped 5 days and plunger stuck.
8/27/2004	Jarred pump to unseat and POOH. PU on tubing, setting in sand. Lay down 2 joints w/ SN at 4,749 ft. TIH w/ pump and rods. Loaded tubing and pressure tested.
	Pump not pumping.
3/27/2006	Performed near-wellbore consolidation treatment.
1/7/2007	Well continues to perform with no issues.



Treatment Volume= 2 frac wings × 1-ft height × 10-ft depth
× 0.25/12-ft width × 0.42 porosity × 7.48 gal/ft^3
× safety factor of 2
≈ 2.5 gal/ft of perforations

Figure 1 — Illustration of a propped fracture located near the wellbore being treated with a small volume of consolidating treatment fluid to lock the proppant in place.

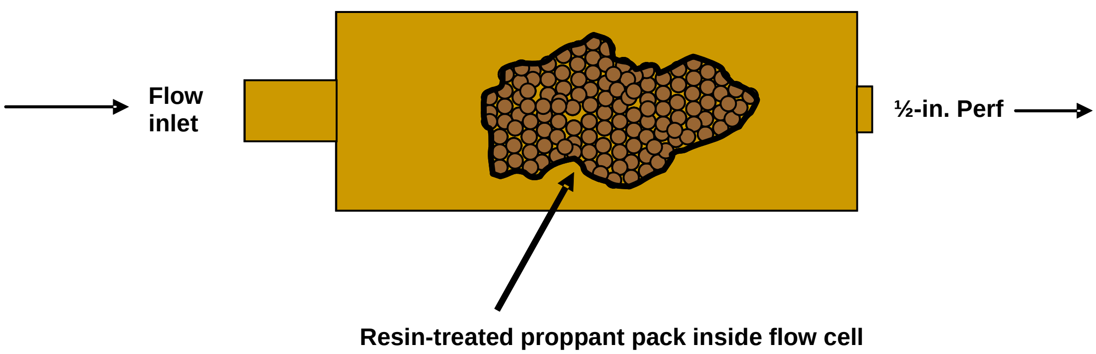


Figure 2a — Schematic diagram showing the proppant pack and flow directions through the flow cell. The flow cell was used in packing proppant, applying consolidation treatment, and testing flowback with water.

Figure 2b — A progressive cavity pump was used in pumping water through the proppant pack at various flow rates to determine the resin performance in controlling flowback of the proppant.

Figure 3—Interior view of a modified API linear conductivity cell.

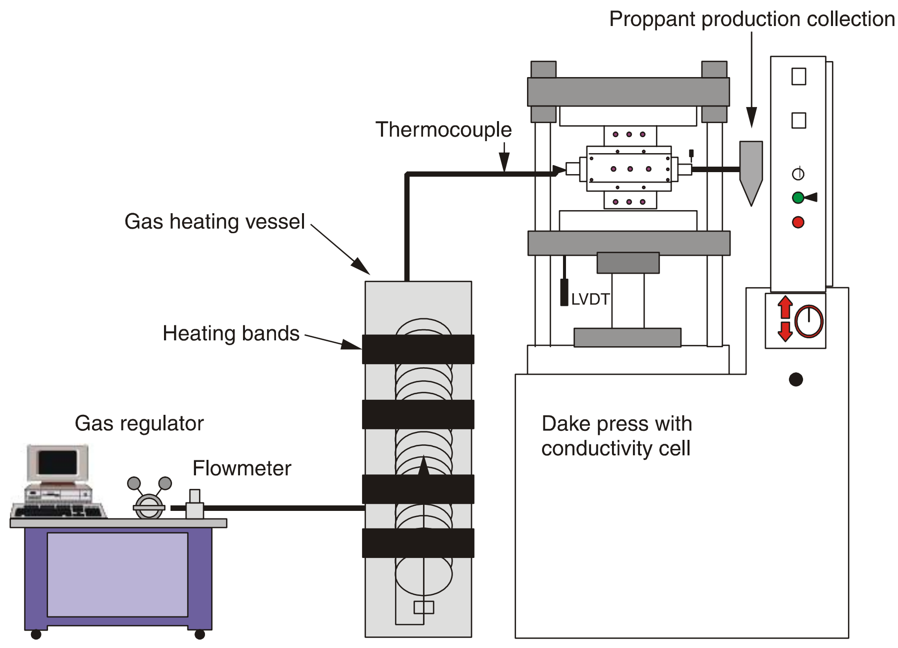


Figure 4 — Schematic diagram of equipment involved in lab flowback testing using high-temperature, high gas flow rates.

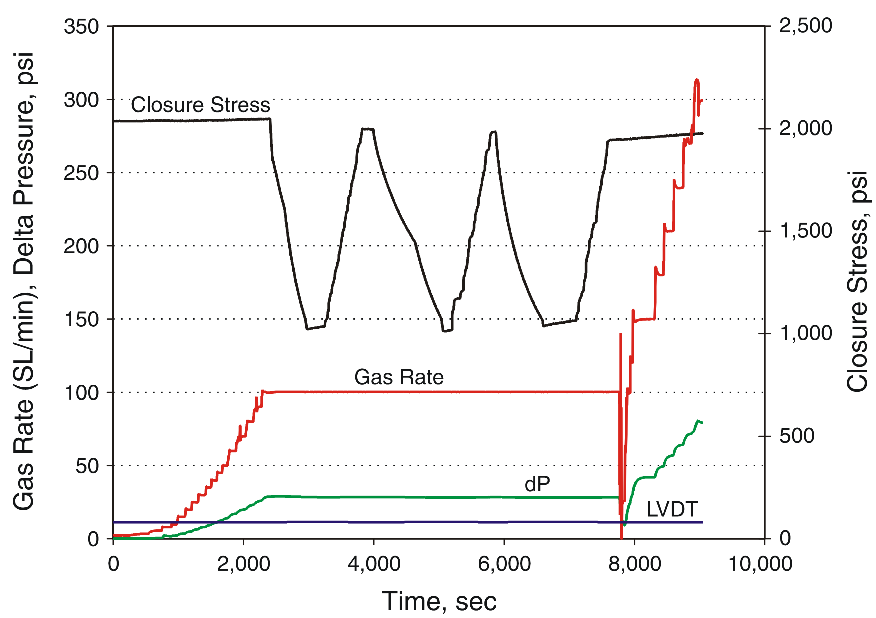


Figure 5—Flow of heated gas to simulate gas production through sand pack treated with liquid curable resin at 175°F.

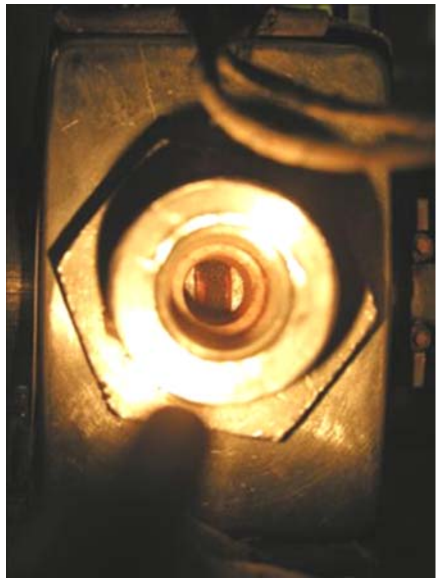


Figure 6—Close-up view of the proppant pack at the outlet end of the flow cell.

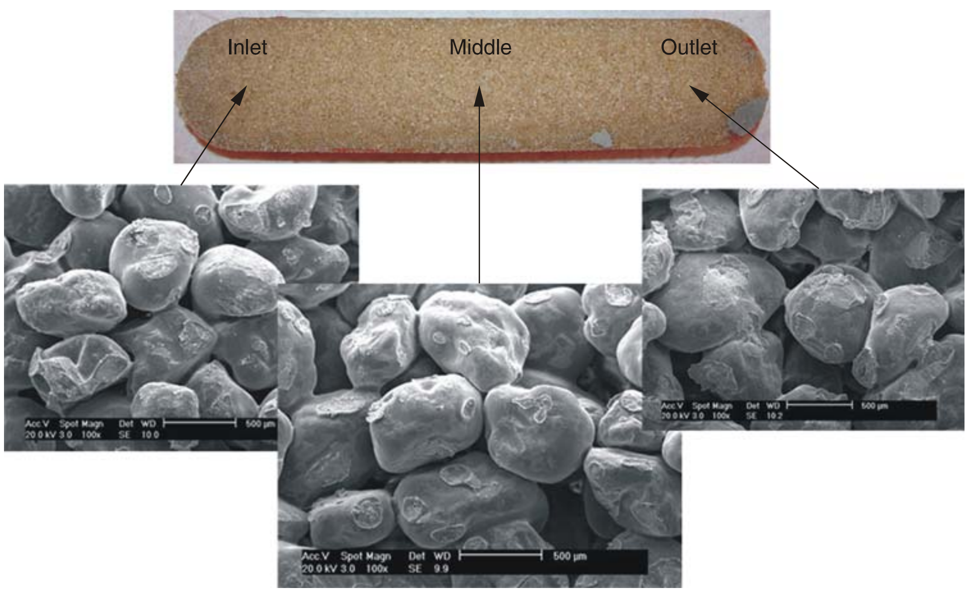


Figure 7 — SEM micrographs of sand pack taken at various locations showing the footprints of contact points and pore spaces between sand grains.

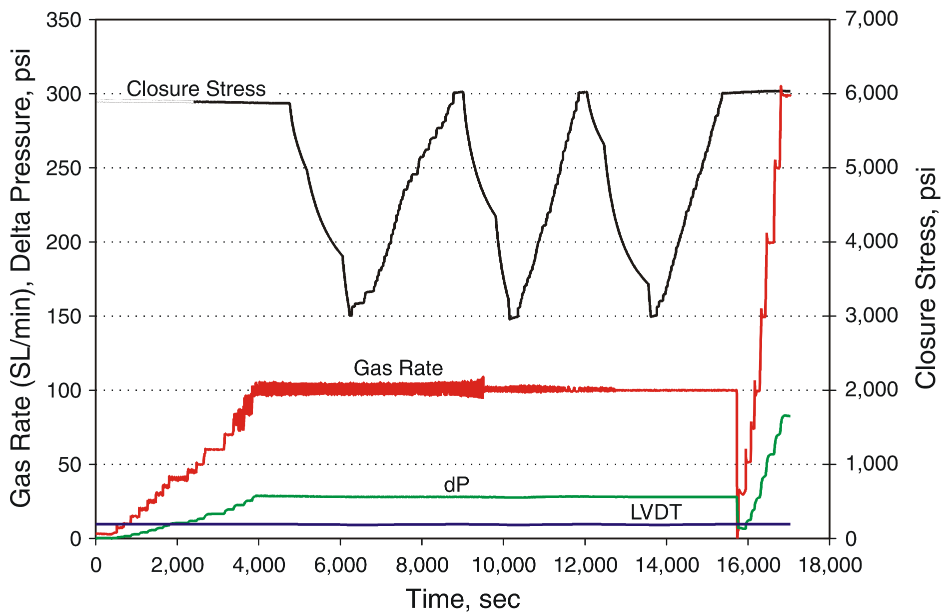


Figure 8 — Flow of heated gas to simulate gas production through bauxite proppant pack that has been treated with liquid curable resin at 250°F.

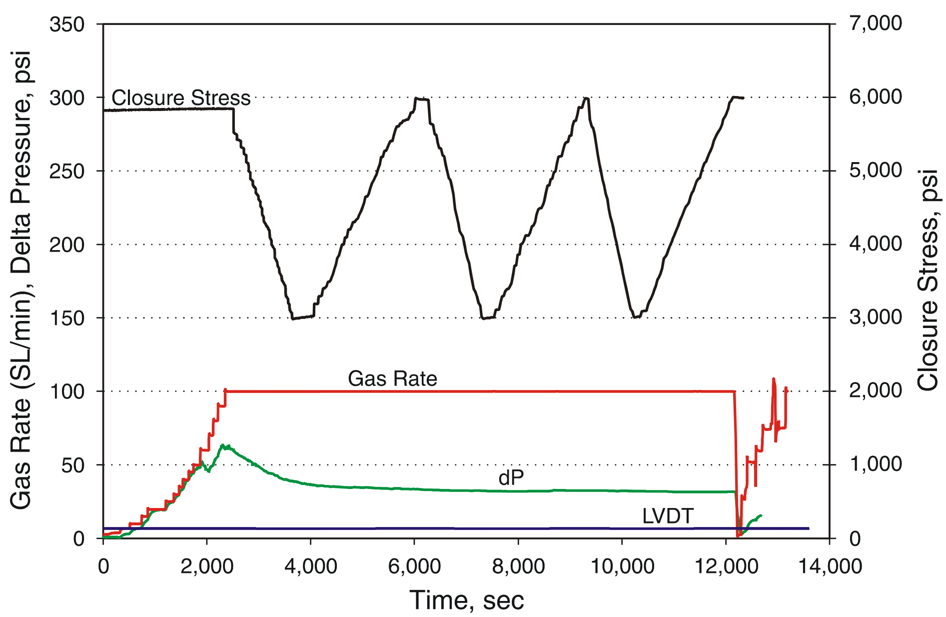


Figure 9 — Flow of heated gas to simulate gas production through bauxite proppant pack that has been treated with liquid curable resin at 350°F.

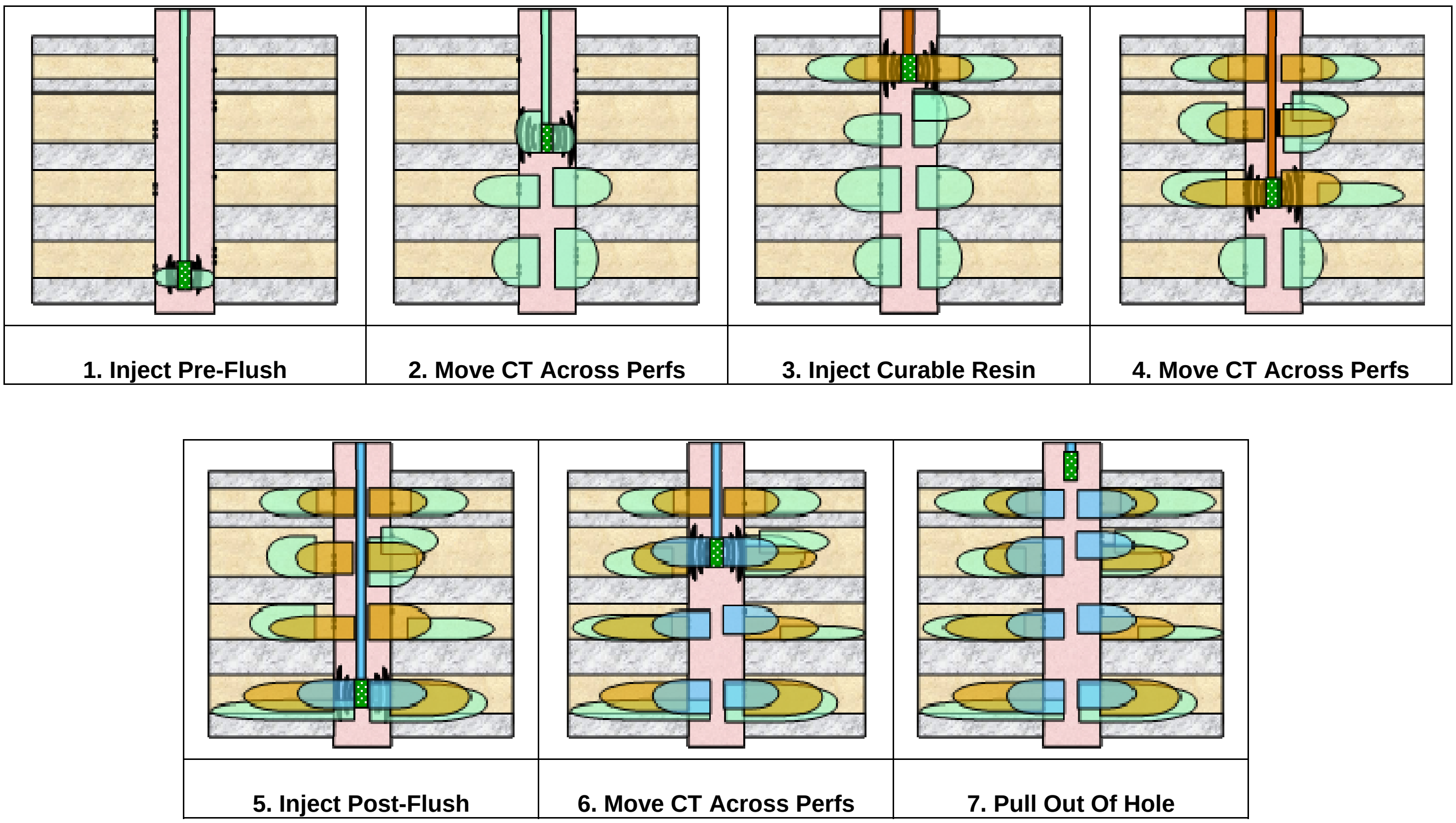


Figure 10 — Treatment process uses a combination of CT, resin consolidation, and pulsing tool Technologies to provide remedial solutions to help control proppant flowback.

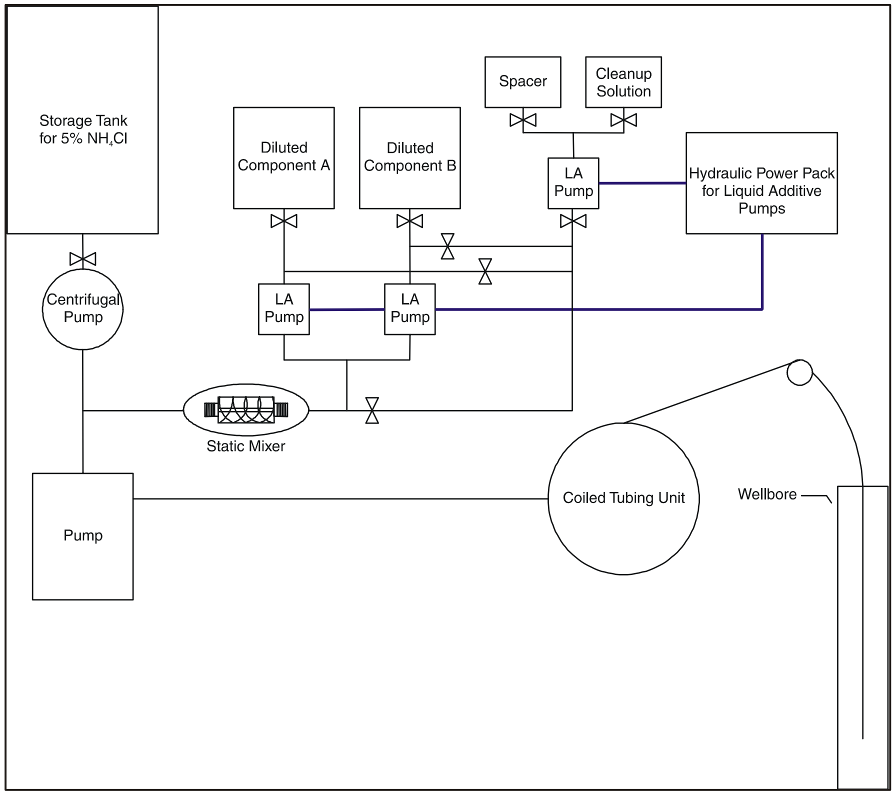


Figure 11—Schematic layout of equipment involved at wellsite for remedial proppant treatment.

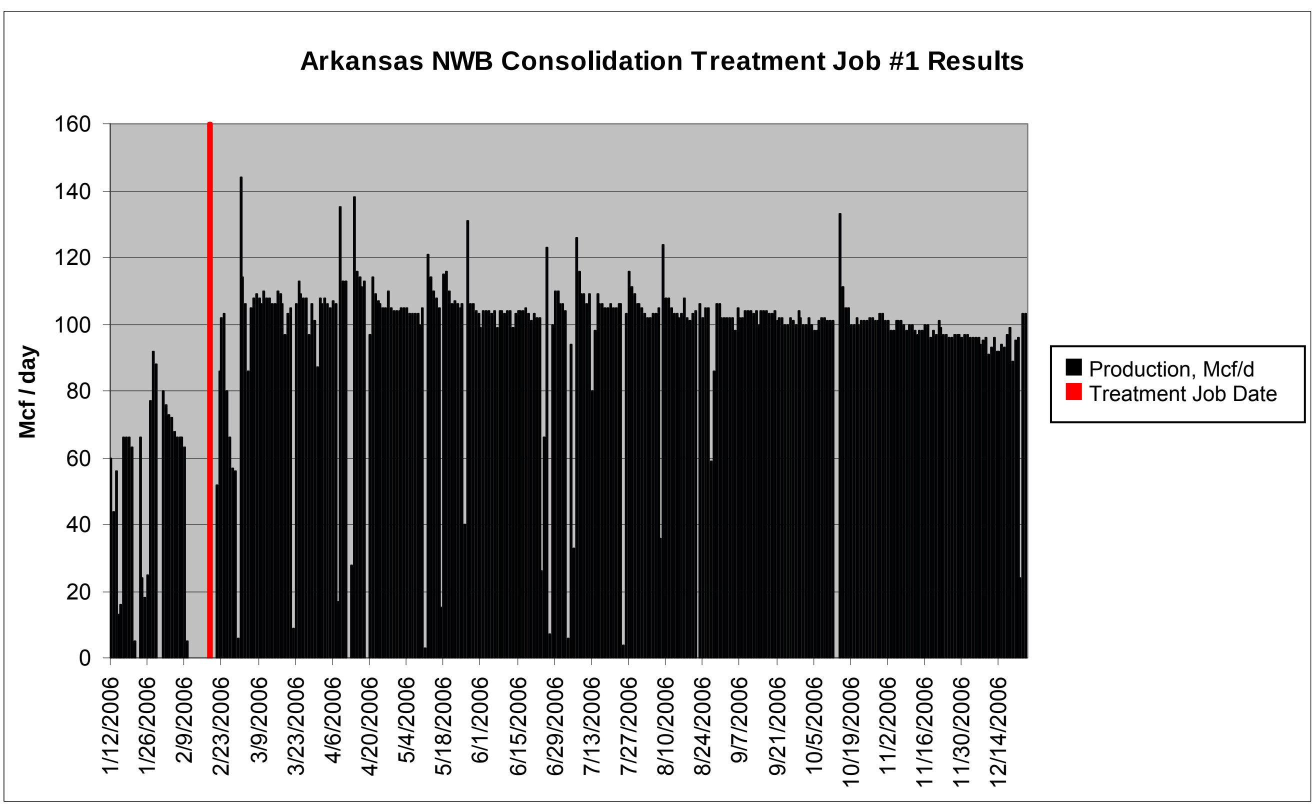


Figure 12a — Production results from Arkansas Well 1. In 10 months, one trip was made to the wellhead post-treatment to check for sand fill; none was found. This well has pumped continually for 10 months with no interruption.

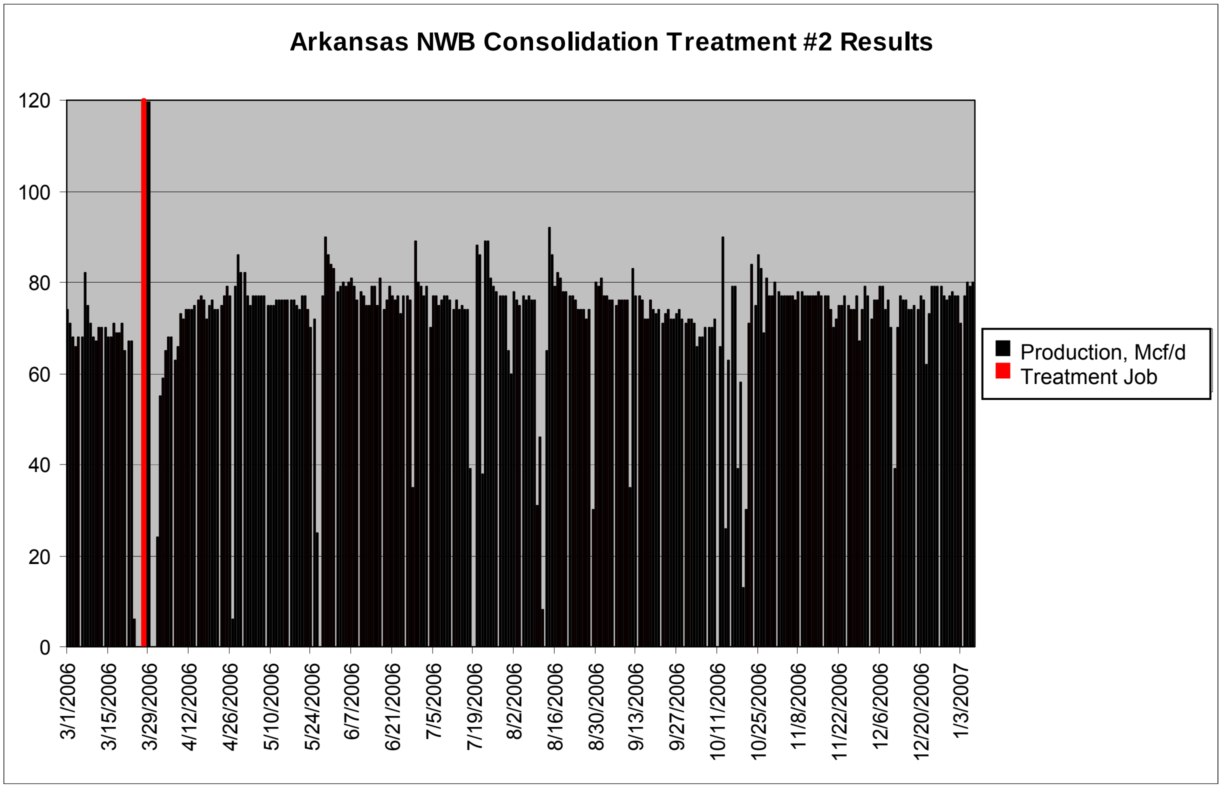


Figure 12b — Production results from Arkansas Well 2. In 9 full months since the treatment, no maintenance work has occurred on this well.

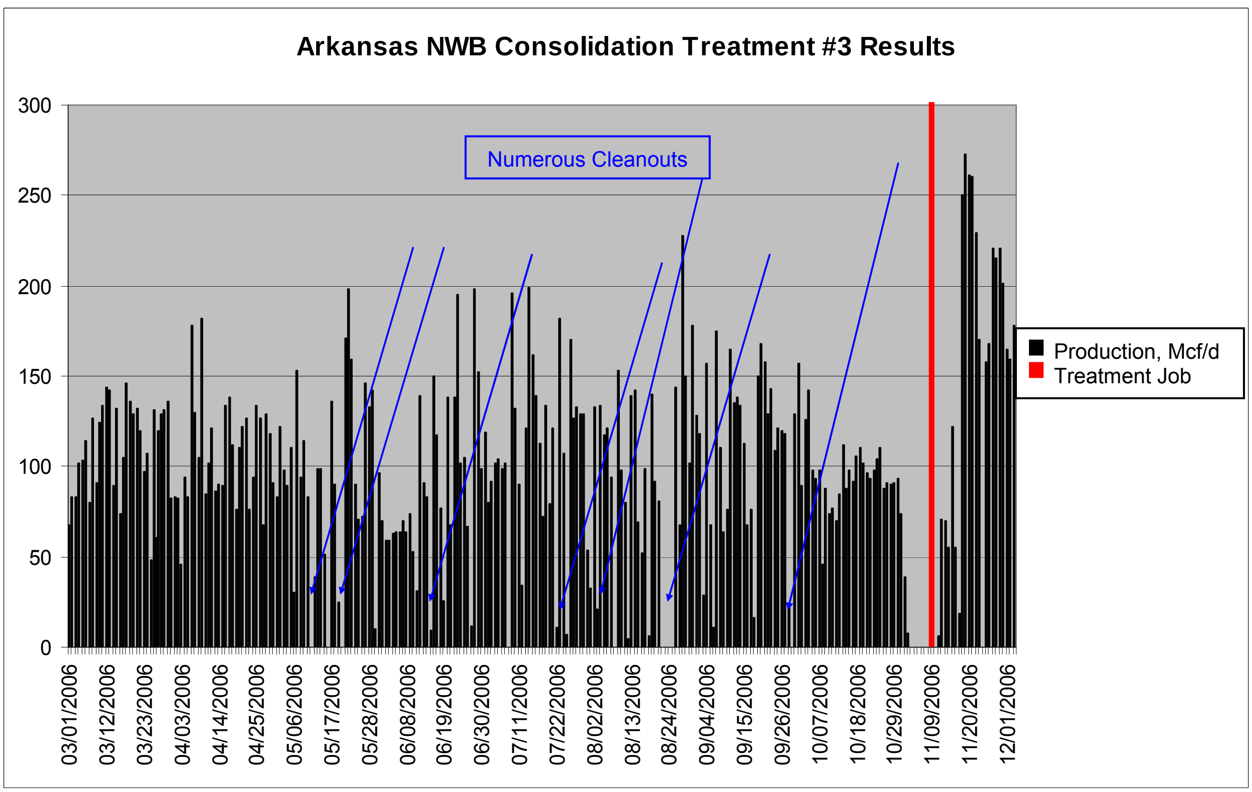


Figure 12c — Production results from Arkansas Well 3. Substantial initial production increase has been witnessed due to efficiently sustaining the rod pump system. The blue arrows highlight the extensive wellbore clean out history prior to the consolidation treatment shown in red.

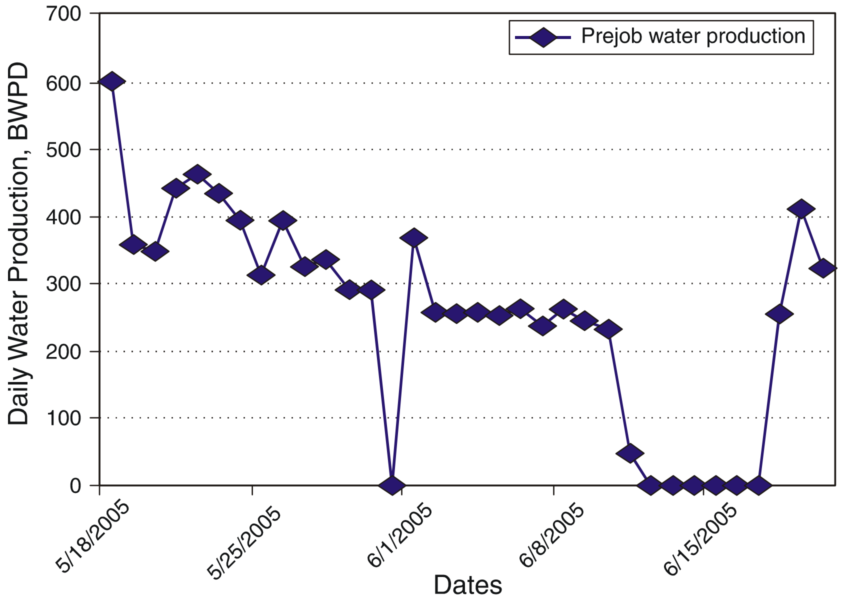


Figure 13a — Water production rate of the well *before* treatment with water conformance polymer and consolidating treatment fluids.

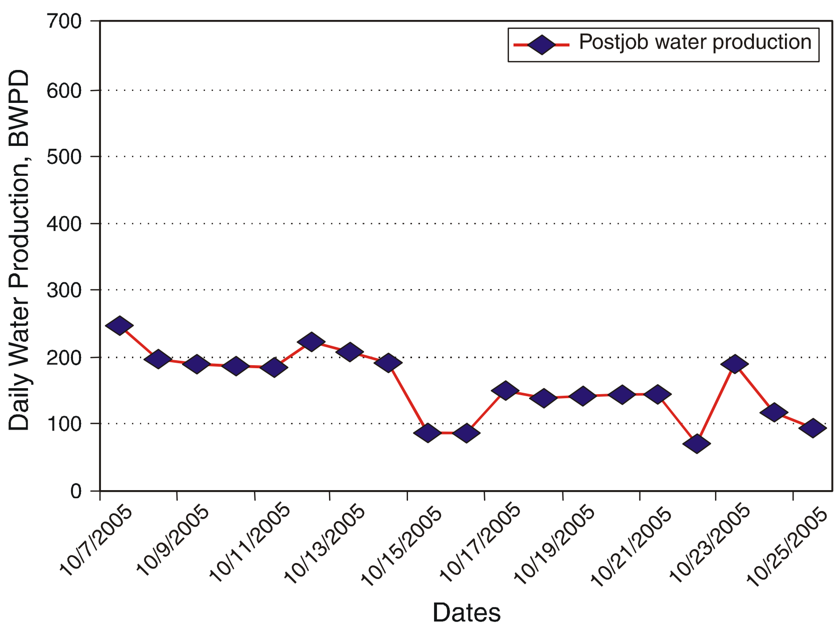


Figure 13b — Water production rate of the well *after* treatment with water conformance polymer and consolidating treatment fluids.