REMEDIATION OF PROPPANT AND FORMATION SAND FLOWBACK IN HIGH TEMPERATURE WELLS—A FIELD STUDY IN SOUTH TEXAS, USA

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ABSTRACT

Flowback of proppant and formation sand can often become problematic for operators because the solids cause equipment damage, costly cleanup treatments, and potential loss of production. These flowback problems are often compounded in severity in wells with high temperature and high pressure. Operators seek reliable solutions to (1) eliminate the need for frequent remedial cleanouts and surface equipment replacement and (2) to maximize revenues by increasing and maintaining production rates.

This paper presents a field case study that discusses the remedial treatments and knowledge gained from more than 20 wells in south Texas where proppant and formation-sand flowback problems have been encountered by the operator. It also discusses the development and treatment processes using low-viscosity consolidating agents to be applied in the treatments. Examples presented illustrate how the problems were successfully overcome in these high-temperature wells.

Field results indicate that more than 90% of these consolidation treatments have effectively stopped the flowback of proppant and formation sand while allowing the production rates of the wells to be increased. These treatments have drastically decreased the number of workovers compared to the period before their treatments, or compared to the offset wells in the same field where consolidation treatments were not performed. This study demonstrated that an effective coating of a curable resin on the proppant and formation sand close to the wellbore is necessary to help maximize the consolidation bonding between grains within the pack while minimizing any reduction of its permeability.

This new remedial-treatment process greatly enhances the effectiveness of fluid placement into the propped fractures, regardless of the number of perforation intervals and their lengths and without mechanical isolation between the intervals. The simplicity of treatment helps make remediation economically feasible, especially in wells with marginal reserves.

INTRODUCTION

Today, maturing assets provide more than 70% of production. Yet the production from these assets has already peaked, stabilized, or declined. Maintaining steady production levels involves continuous management and maintenance of these ever-changing wells. Mature assets compete with new fields for capital and personnel. To receive adequate monetary support for management and maintenance, these wells must be able to deliver a comparable cost to that of a new asset in early development in a company's portfolio to lift the hydrocarbon equivalent.

A mature asset faces many challenges that require constant management. These challenges can include depleted pressure regimes, depleted hydrocarbon layers, inefficiently swept zones, and undesired production of water, proppant, formation fines, gas, hydrogen sulfide, and carbon dioxide. These problems not only require additional maintenance procedures but also advanced health-, safety-, and environmental-compliance protocols because of the conditions noted above.

Problems associated with maturing wells directly hinder efforts to find more recoverable hydrocarbons, increase production, and improve recovery. Increased operating expenditures and capital expenditures are common with these persistent problems. One of the most assiduous industry problems is solids flowback, which costs operators millions of dollars every year through the loss of production, remedial procedures, and expensive equipment damage.

Because most of the wells are not completed with 180°-phasing (oriented) perforations, not all perforations are aligned with the propped fractures. The nonaligned (out-of-phase) perforations located in poorly consolidated formations are prone to producing proppant or formation sand during production (Fletcher et al. 1996). The resin treatment described in this method can provide an effective means for sand control by consolidating the formation sand surrounding all the perforations in low- or highly-permeable areas. The production of formation sand and fines particulates is an expensive area to address with solids production. It is often preceded by water intrusion, where the cementation between formation sand grains can deteriorate, allowing the formation sand and fines to migrate, or produce, with the production fluids. The fines migration often causes formation damage as pore channels or flow paths become plugged with fine particles. There are situations where concurrent production of both solids occurs, which worsens the situation.

Normally, fracture-stimulated wells encountering these problems can experience a wellbore-filling effect in which the wellbore essentially becomes filled with proppant and/or formation sand. This accumulation of solids can choke off production flow paths and seriously damage or destroy downhole-lifting and surface-production equipment.

Rectifying these inherent problems requires costly wellbore cleanouts to re-establish normal production rates. Presumably, these remedial cleanouts represent a large portion of the asset’s accrued operating expenditures. Based on market knowledge and data reported by an industry consultant, more than 25% of the global use of coiled tubing (CT) is for cleaning out wellbores and amounts to $475 million annually, not including lost production, equipment repair, or replacement costs.

One remedy to this pervasive industry problem might be the new remedial-solids flowback treatment (RSFT) process, which uses the combination of resin-consolidation technology, CT, and pulsing-tool technology to provide an effective remedial-treatment solution to proppant production and control the influx of formation material. The following information is a case study of more than 20 treatments where RSFT was applied with more than 90% success in terms of flowback control of solids and well-production performance.

NEW TREATMENT METHOD

Individually, CT, consolidating fluids, or pressure-pulsing tools do not represent new technology. However, the combination of these technologies offers a viable solution to the proppant-flowback problem after the proppant has been placed in the fracture. This new method involves using CT or jointed pipe coupled with a pressure-pulsing tool to enhance the successful placement of a relatively thin fit-for-purpose consolidating-treatment fluid into the near-wellbore region of propped fractures and the formation’s surrounding perforations. This approach treats the existing proppant and formation sand in the near-wellbore region to help reduce or eliminate current and future solids production and its related problems. In addition, the treatment process moves fines and debris away from the near-wellbore proppant-pack region, which helps restore and maintain the conductivity of propped fractures.

PRESSURE-PULSING TOOL

The pressure-pulsing tool uses technology that helps assure fluid penetration into the proppant pack or formation matrix and can be used in conjunction with CT or jointed pipe. The tool is geared to generate fluid oscillation, which in turn, produces emissions of alternating bursts of fluid that create pulsating pressure waves within the wellbore and formation fluids in the porous media. These pressure waves can break up many types of near-wellbore damage, helping restore and enhance the permeability of the proppant pack in the perforations and in the near-wellbore area. The pressure waves expand spherically, producing 360° coverage that provides dynamic isolation as the tool is reciprocated throughout the perforated interval. As damage is removed, the fines are pushed farther away, and the pressure waves enhance the penetration of treatment fluid deeper into the fractures and formations (Webb et al. 2006).

CONSOLIDATING FLUIDS

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 (Cole et al. 1999). Applying large volumes of curable resin with an ineffective placement technique does not guarantee a remedial solution to the proppant-flowback problem. The treatment can be expensive and might not produce the desirable results.

Conventional curable resins that have been used for coating proppant on-the-fly to provide proppant-flowback control (Nguyen et al. 2003) have high viscosities compared to the new consolidating treatment fluids that are being used in this study of remedial-proppant treatment. If conventional resin was placed into the propped interval, it would be difficult for the excess resin to be displaced or removed from the pore spaces by the postflush fluid that typically has a much lower viscosity. Ineffective displacement of the resin from the pore spaces will result in conductivity loss in the proppant pack or permeability damage in the formations.

Because the bottomhole temperatures (BHT) of the wells in south Texas were mainly above 250°F, a high-temperature, furan-based resin system was selected for the treatments. This liquid curable resin (LCR) was formulated to have low viscosity and be a one-component system that requires only temperature and time to activate and allow the resin to be cured without applying an external catalyst. It can handle wells with BHTs up to 550°F. Additives included in the liquid-resin system permit good consolidation properties in the proppant pack, allowing it to effectively handle the shear forces of high production rates and the effect of stress cycling as the well undergoes producing and being shut in.

The LCR is metered into the flowstream on-the-fly and the resin solution is then pumped downhole to coat the proppant in the fractures. Rather than an instant cure, curing of the LCR takes place slowly, which allows 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 before the resin cures to the point where placement is prohibited.

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

1. Inject a volume of preflush fluid to remove fines, oil residue, and any other materials blocking direct access.
2. Inject another volume of preflush fluid to prepare the surfaces of proppant and formation particulates so they accept and allow the resin to coat the surfaces.
3. Inject a volume of LCR treatment fluid to coat the proppant/formation fines and establish consolidation between grains.
4. Inject a volume of postflush fluid to displace the excess resin from occupying the pore spaces within the matrix of the proppant pack, thereby minimizing the damage to the pack permeability.

Figure 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, rather than trying to treat 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 plugging in the pore spaces of the proppant matrix.

GENERAL AREA AND WELL PROPERTIES

The analysis on the treated Wells A, B, C, D and E is consistent with the remaining case-study wells, as well as other maturing wells located in Webb and Zapata counties in Texas. The majority of the wells in the case study were spudded in the mid-70s to mid-80s. Wells in this area are typically completed with 9 $^{5}/_{8}$-in., 36-lbm/ft surface casing, 7-in., 23-lbm/ft intermediate casing, and 4 ½-in., 11.6-lbm/ft production casing. Following completion, many of these wells were produced through 2 $^{7}/_{8}$-in. and 2 $^{3}/_{8}$-in. tubing (Figure 2). The main formations targeted in these areas are Lobo and Wilcox, with common low-permeability (0.01 to 0.08 mD) sandstones in south Texas, a BHT gradient of roughly 1.75°F per ft, and a bottomhole pressure gradient of ~0.75 psi/ft. The multizone layers in this area typically consisted of 10 to 300 ft of perforations, and were often perforated with 2 shots/ft.

Stimulation practices performed on these wells predate modern stimulation techniques typically performed today in this area. These wells were stimulated with roughly 500,000 gal of fracturing fluid, carrying 1.5 million lbm of Ottawa sand, without any proppant-flowback-control additives. Current stimulation treatments on Lobo and Wilcox typically carry low- to moderate-strength ceramic proppant in the amount of 150,000 to 300,000 lbm and are pumped at a rate of 25 to 45 bbl/min with a crosslinked carboxymethylhydroxypropyl-guar fluid. Stimulating with a resin-coated ceramic or bauxite, tailing in with a resin-precoated ceramic or bauxite proppant, or running a resin coating on-the-fly are also common practices in the area to help reduce the chances of producing proppant later in the well's life.

PRODUCTON HISTORY AND PROBLEMS

After being completed and turned over to production more than twenty years ago, an average production-decline rate of 30% was seen in these assets (production illustrated in Figure 3).

Over time, these assets have endured solids-producing problems that have diminished overall cumulative production and return on investment to the operator. Throughout the years, numerous maintenance problems have been recorded with these wells associated with flowback of proppant and formation sand that caused equipment damage, costly cleanup treatments, and potential to total loss of production. Because of the increased costs, these wells are candidates for RSFT service.

As previously mentioned, the majority of proppant-flowback issues were precipitated by the large fracture-stimulation job during the well's completion. Over time, this persistent problem reduced the efficiency of the wells to stabilize gas production and created problems associated with the costs described below.

Almost inherently, a large amount of the capital expenditures consisted of a well-intervention type solids-cleanout of the wellbore and surface equipment repair. Slickline and CT were the most common types of cleanout processes because surface-equipment repair also hindered daily and cumulative production. For instance, from January 1, 2005, Well A experienced more than 215 days of lost production and produced an average of 90.8 Mcf/D while online. In the months leading up to the RSFT, the surface equipment needed to be replaced and/or the wellbore needed to be cleaned out every two weeks on average.

On a per-well basis, typical cleanout costs with slickline to dump bail-accumulated solids in efforts to re-establish old production rates were $7,500 daily. For example, Well A had 16 (recorded) slickline cleanouts associated with solids production leading up to the RSFT.

To rectify and re-establish lost production, CT was commonly used to clean out the accumulated proppant, costing $95,000 per cleanout. These costly cleanouts were often performed multiple times to re-establish production. The solids-flowback problem also increased operating costs by necessitating replacement and repair of surface equipment and labor for cleaning separators and flow lines. Surface equipment (valve, seat, and trim) that was damaged and replaced because of the solids-flowback sandblasting effects were approximately $1,500 and occurred twice monthly on average.

PROVIDED SOLUTION

The operator teamed with the service company to deploy the new RSFT process as a solution to its solids-flowback problems in the Lobo field. As stated previously, the RSFT process uses the combination of resin-consolidation technology, CT, and pulsing-tool technology to provide an effective remedial treatment solution to proppant production and control of the influx of formation material. RSFT treatment is a rigless intervention process that requires no isolation packers, reducing time, cost, or risks of a conventional workover. The equipment required is limited for the RSFT process and only requires a small location footprint. Equipment dispatched to the well site included a 1¼-in., 38K CT unit, a single-pump truck, a chemical-delivery unit, and a nitrogen unit to aid in the cleanout.

Selecting a suitable resin formulation and applying an appropriate placement method must go hand-in-hand to ensure the success of the treatment. The design for the RSFT treatment is specific to the flowback issue determined on each individual well. Flowback samples were first obtained from the well's surface equipment and sent to the service company's field laboratory for analysis to verify the substance and size of the sample. The flowback sample taken from the treated wells were found to be fine-grained formation sand and white-colored proppant, on average. The proppant was found to be fragmented and crushed, with few whole and intact white-colored proppant spheres. The sample had a slight reaction to 15% HCl, was not magnetic, and tested positive for iron. Based on the lab results, the RSFT treatment was tailored to remediate this specific flowback issue.

CT was deployed to wash out sand from the wellbore, and the RSFT treatment fluids were designed with their appropriated treatment volumes. The CT tool bottomhole assembly (BHA) needed to properly deliver the treatment fluids to the perforations was minimal. It included a CT connector, centralizers, backpressure valve, and most importantly, the fluid-pressure wave tool.

The pressure wave tool was needed to create multiple pressure pulses directly across the perforated interval and allow the low-viscosity, proppant-consolidation treatment to enter into the formation more effectively to consolidate the proppant within the existing fracture while being reciprocated through the interval. This pulsing technique does not require mechanical isolation between intervals and is an efficient, inexpensive method for delivery of the RSFT treatment.

RSFT GENERAL PROCEDURE

The chemical treating fluids used in this process, when properly deployed, were found to offer no obstruction to the wellbore or completion and were suitable to be placed in multiple intervals in one treatment operation. The process is as follows (Figure 4):

1. The well is cleaned out and any fill is removed to below the bottommost producing interval.
2. A pressure-pulsing tool is installed on the bottom of a typical CT (or jointed pipe) BHA.
3. The CT is deployed into the well to the topmost producing interval.
4. A first preflush fluid is pumped through the pressure-pulsing tool and into the producing interval. This cleans the proppant surface and prepares it to receive the LCR. The CT annulus is closed during this process (Figure 4.1).
5. The BHA is moved downward across each producing interval in the wellbore (Figure 4.2), and the second preflush fluid is then repeated as the BHA is moved upward again, past each producing intervals (Figures 4.3 and 4.4).
6. Once at the top of all producing intervals, the LCR is pumped through the pressure-pulsing tool, directly adjacent to the producing interval being treated (Figures 4.5 and 4.6). 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.
7. Now at the bottommost interval, a final postflush fluid is displaced and injected through the pressure-pulsing tool and into the producing interval to remove excess LCR from plugging the pore spaces of the proppant pack (Figures 4.7 and 4.8).
8. This process is continued as the CT is withdrawn until it reaches the uppermost producing interval (Figure 4.8).
9. The CT is then pulled out of the well, pumping only enough to keep static pressure within the wellbore with the CT annulus still closed (Figure 4.9).
10. As the CT is removed from the well and the well is shut in, a cleanup solution is injected through the CT to clean and prevent the equipment from contamination with LCR residue.
11. The well remains shut in for a period of time, depending on the BHT of the well (from 24 to 72 hours).

During the curing period of the resin, it is recommended that the well is shut in to (1) prevent or minimize fluid swabbing, backflow, or crossflow (which might disturb the cohesion between proppant grains) and (2) to allow the resin to cure properly.

POST-TREATMENT PRODUCTION RESULTS

The treated wells are placed back online with an initial production that is usually exceeded before production by about 100 Mcf (average). The wells have been 90% effective in stopping solids production, with most wells having no indication of sand flowback. Since the time of the treatment, no sand has been produced, surface equipment has been sand-free, and economic production has been restored. These wells are currently on pipeline-production pressure-intermitters that can be viewed on the production charts.

Post-treatment productions, illustrated in Figures 5 through 9, demonstrate that RSFT treatment has successfully eliminated routine wellbore cleanouts, costly workovers, pump and separator repairs, and lost-production time caused by formation-sand and proppant flowback. As such, the RSFT process has shown immediate, significant, positive results. To date, the operator and the service company have treated more than 20 wells in the south Texas Lobo field and have plans for several more.

Once properly cured, the resin-treated proppant pack is resistant to most chemicals. Lab testing has shown that the resin coated on the proppant can handle the effects of stress cycling. The resin-treated proppant pack should survive many years as long as the drag or shear force generated by the production flow rate stays below the cohesion strength established by the resin bond between proppant grains.

RECOMMENDATIONS

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

- Discuss the solids production in detail to determine if the well in question is a viable candidate for RSFT, both feasibly and economically.
- Review the well parameters and produced-solids rate and characteristics thoroughly to plan the treatment to fit the need.
- Select the appropriate consolidating treatment fluids, including preflushes, consolidating agents, and postflushes. In addition, determine the appropriate treating volumes for each individual case.
- An LCR solution that can provide an unconfined compressive strength of at least 50 psi will typically be recommended for use in the remedial proppant treatment.
- CT is the preferred placement technique for accurate coverage, penetration, and overall treatment consistency.
- Always maintain a static to positive pressure during removal of CT or jointed pipe from the well to ensure swabbing action will not jeopardize permeability before shut in for curing of consolidating treatment fluid.
- Respect the shut in times; insufficient cure time only endangers the well's permeability and ultimately well production.

CONCLUSIONS

The production of proppant and formation material is a pervasive industry problem that hinders production worldwide. When examining production losses coupled with resultant expenditures caused by maintenance, equipment repair, and replacement, this problem is one of the largest detriments to an asset's profitability and the operator's return on investment.

The RSFT process implemented has proven that the treatment produces immediate and long-term results. This process successfully eliminated formation-sand and proppant flowback, allowing stabilized production (illustrated in Figures 5–9) without routine wellbore cleanouts and surface equipment replacement.

The case study results show that RSFT provides an effective solution to the fundamental causes of solids flowback, a remedy to an age-old industry problem that is escalating in today's market landscape as additional production assets mature and operators demand higher return on investment.

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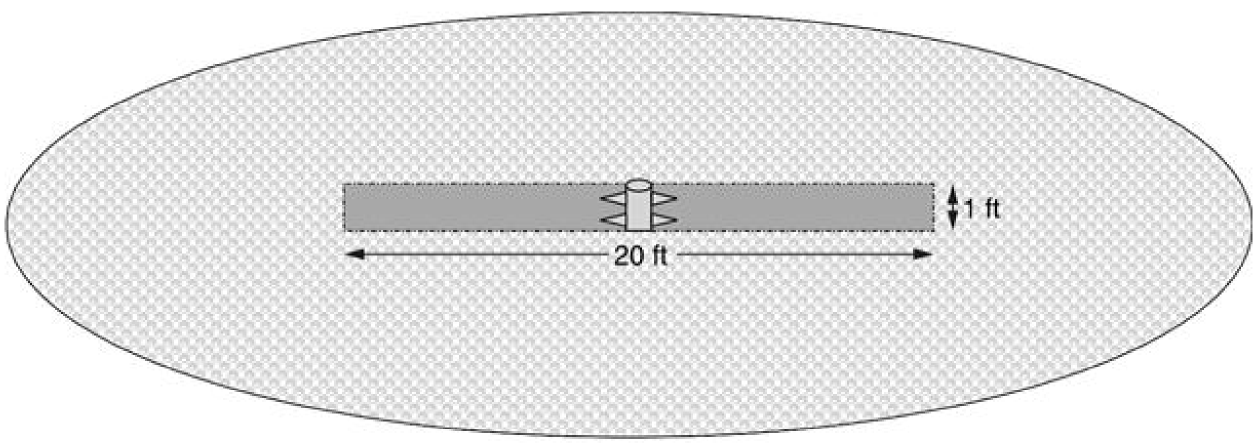

Treatment Volume = 2 Frac wings x 1-ft height x 10-ft depth
x 0.25/12-ft width x 0.42 porosity x 7.48 gal/ft^3
x safety factor of 2
≈ 2.5 gal/ft of perforations

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.

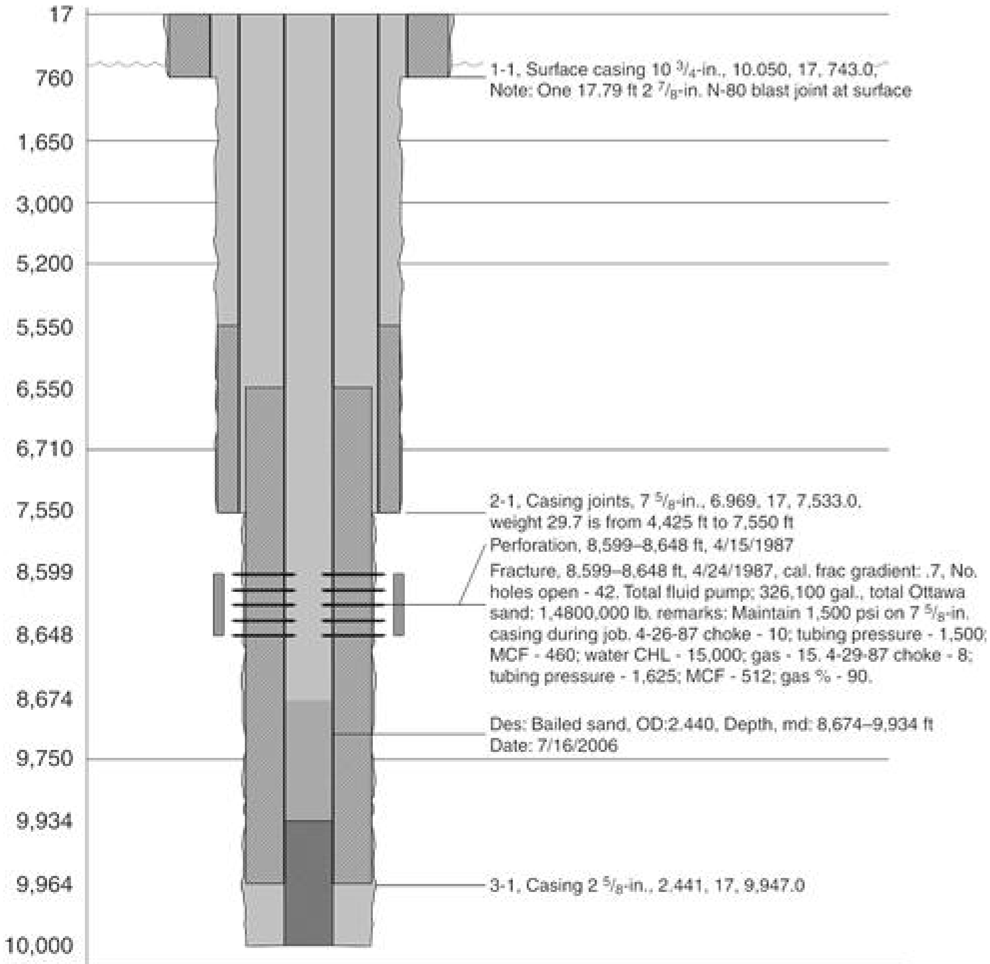

Figure 2—A wellbore configuration.

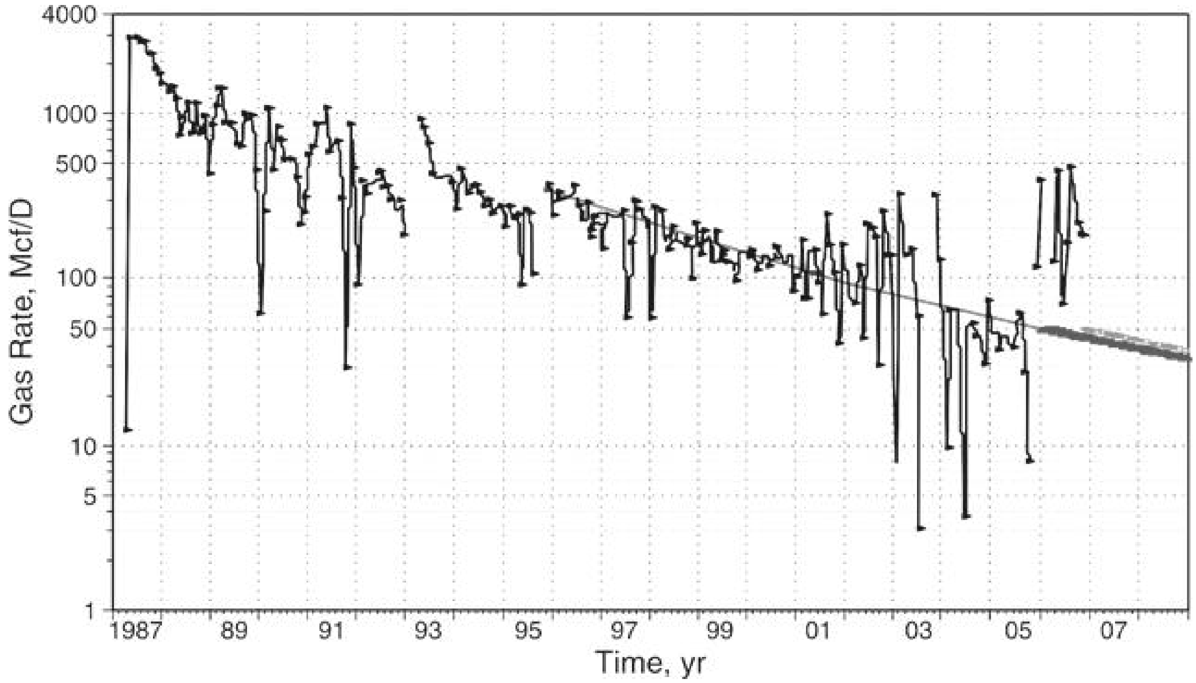

Figure 3—Production life.

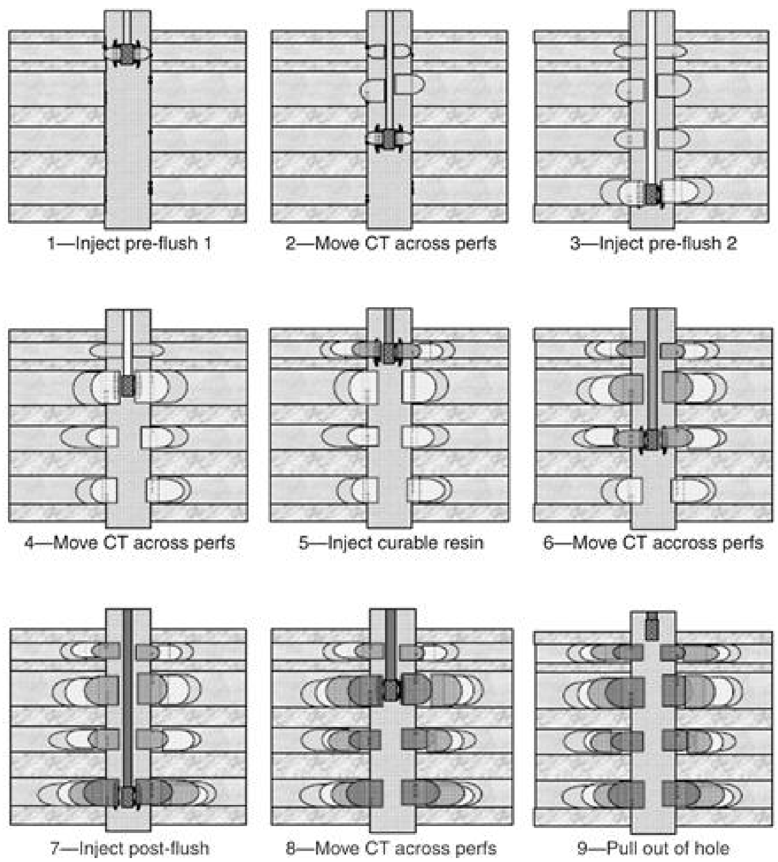

Figure 4—Treatment process uses a combination of CT, resin consolidation, and pulsing-tool technologies to provide remedial solutions to help control formation sand and proppant flowback.

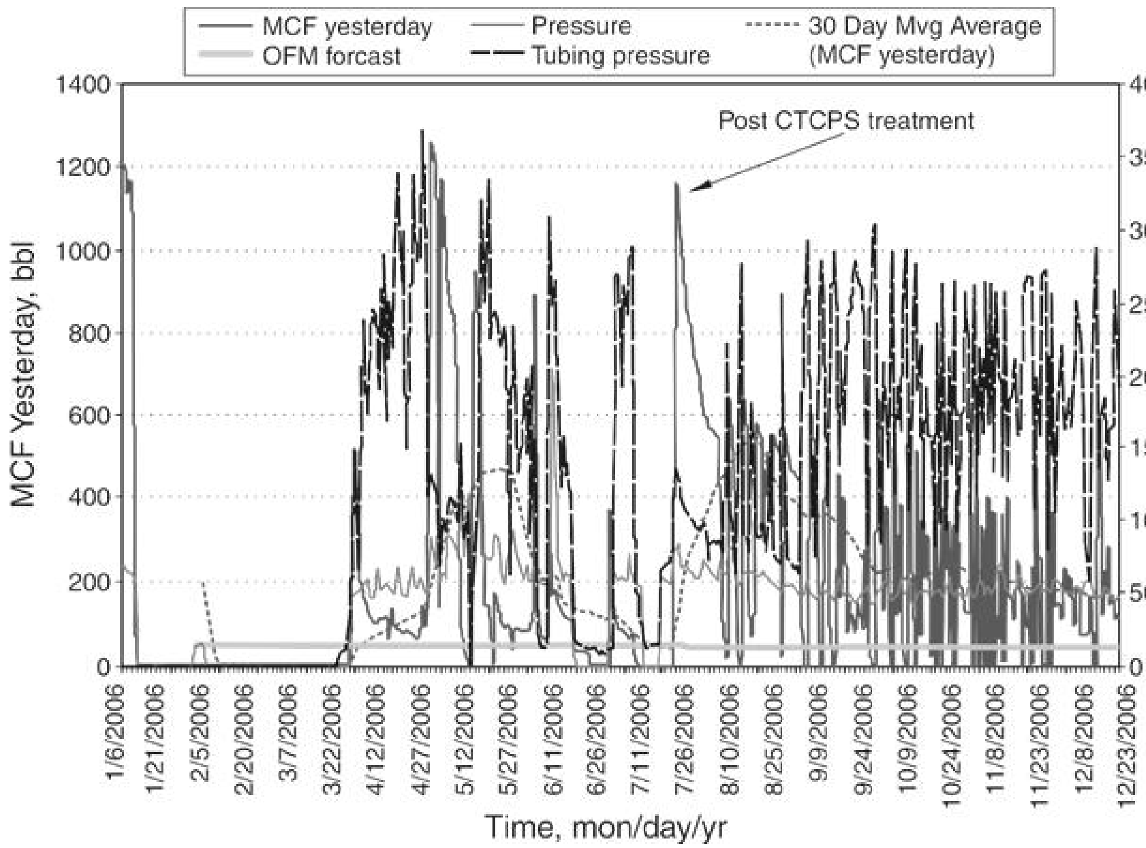

Figure 5—Well A post-RSFT production (intermittent flow).

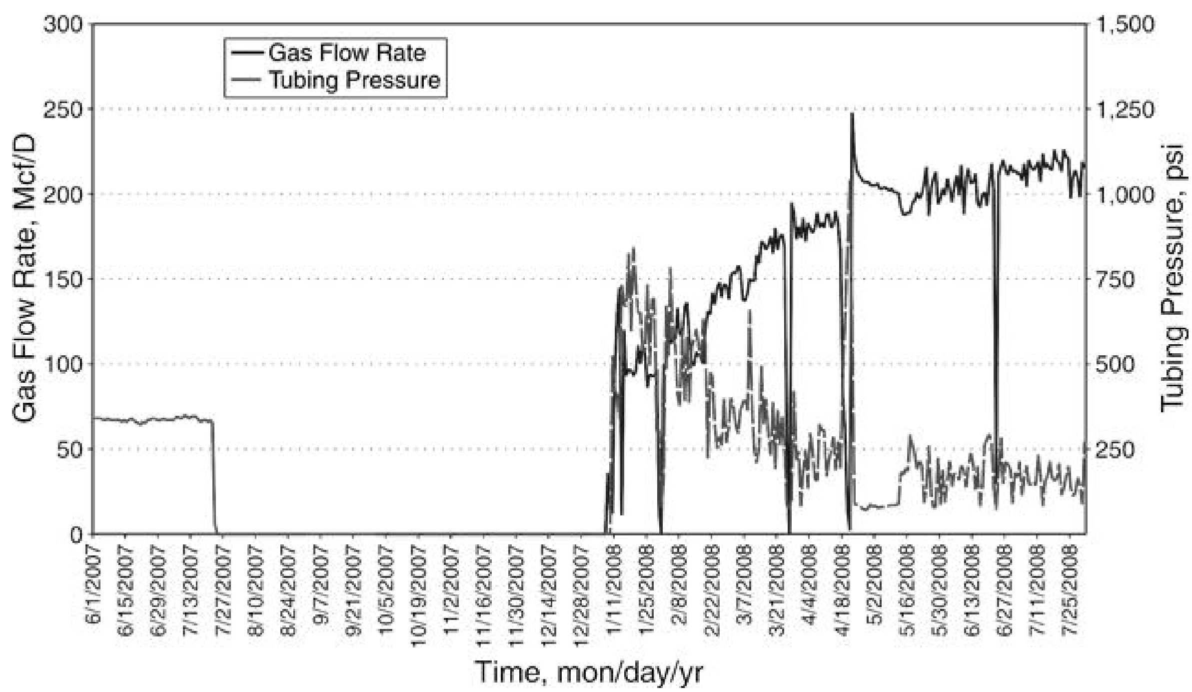

Figure 6 — Well B. This well had not produced since July of 2007. When it was treated in January, 2008, production immediately increased to 200 Mcf/D. As of July, 2008, its production was still increasing.

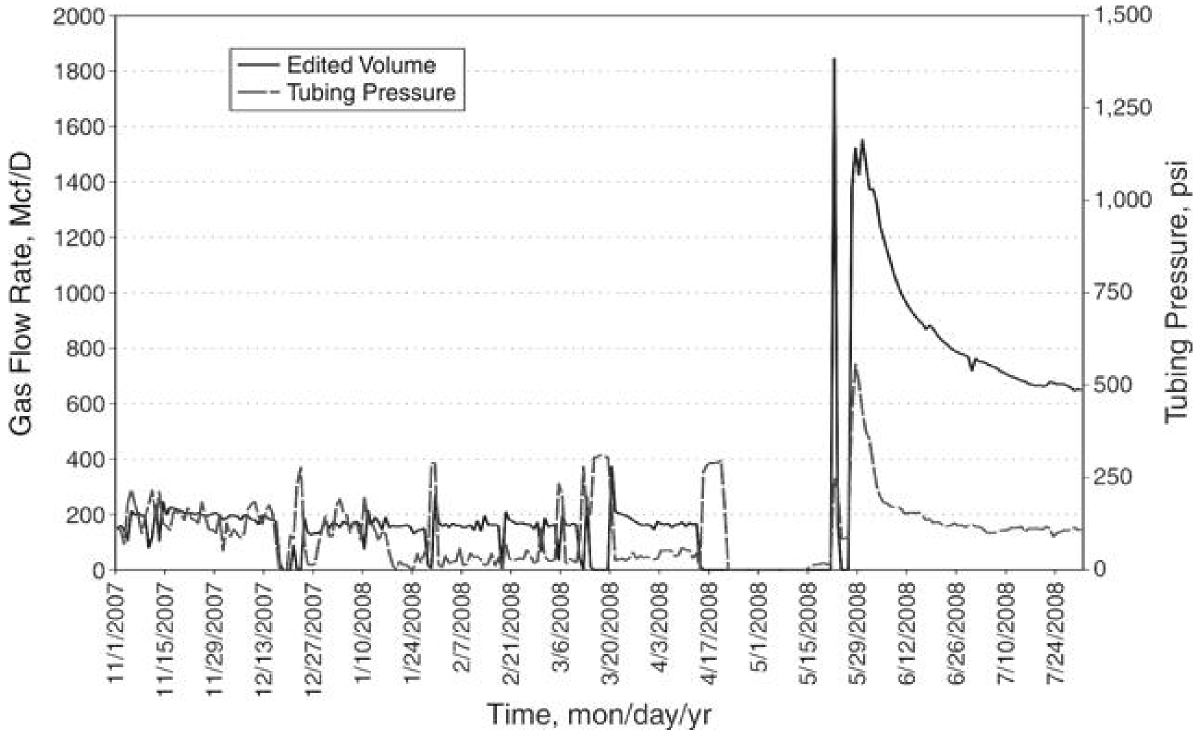

Figure 7—Well C. This well has had sporadic production averaging around 160 Mcf/D before being treated with RSFT in mid-May, 2008. After being treated, the production jumped to more than 1 MMcf/D before leveling out around 500 Mcf/D.

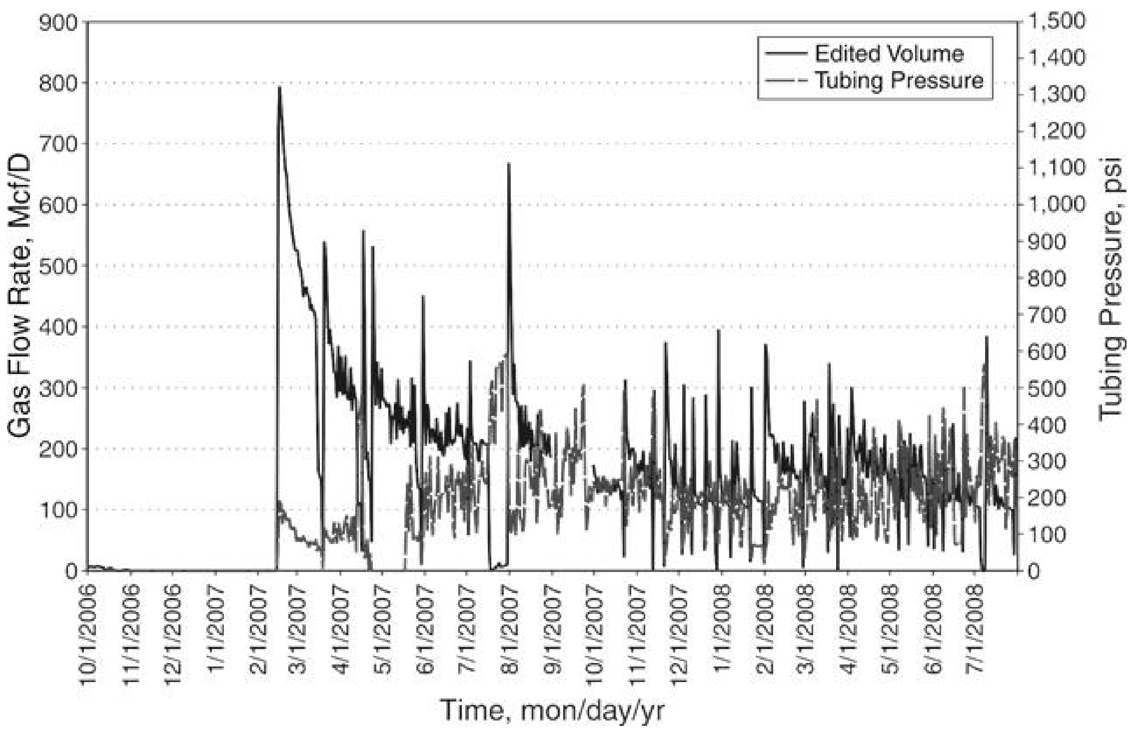

Figure 8—Well D. This well had not produced in four months because of solids production. After a RSFT treatment in early February 2007, the production spiked and has since stabilized at 150 Mcf/D more than 17 months later.

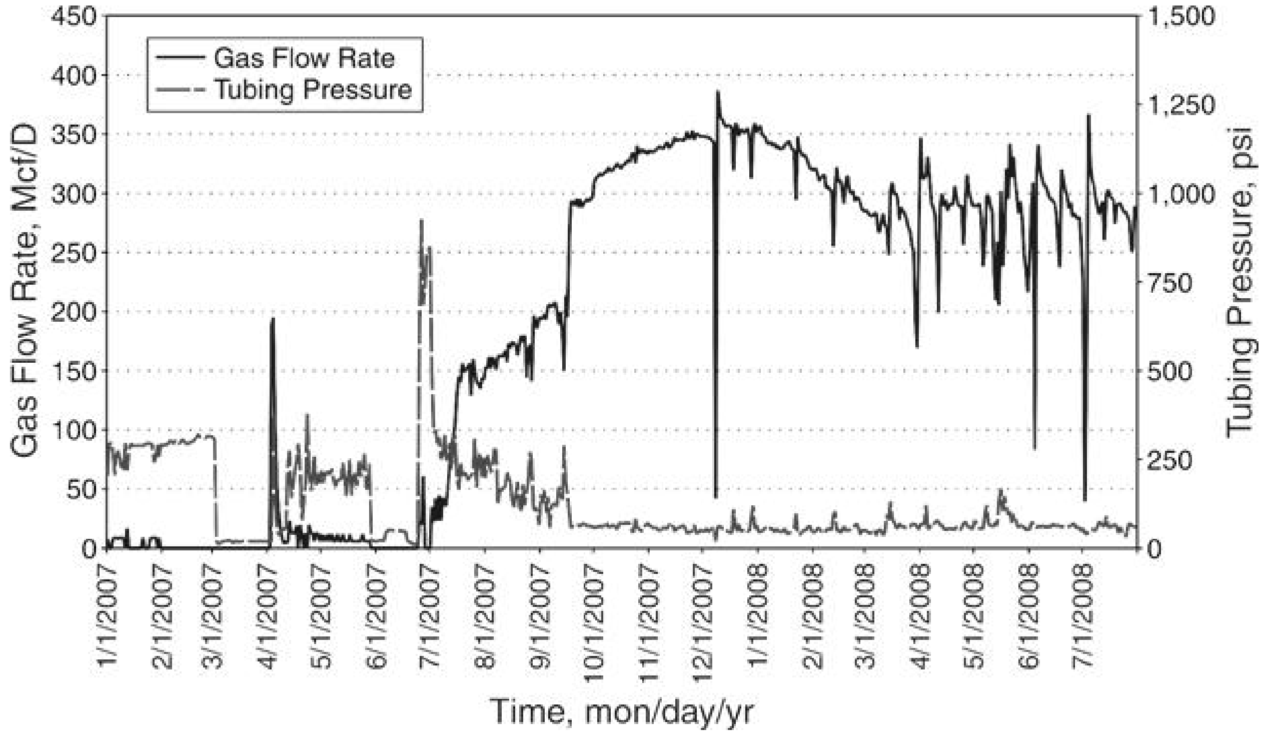

Figure 9—Well E. This well was producing less than 10 Mcf/D since January, 2007.
After treatment in July 2007, initial production jumped to 350 Mcf/D, and then leveled off to 275 Mcf/D where it is currently producing.