Production Acceleration or Additional Recovery? A Look Back at Three Published Field Trials—Long-Term Benefits of Improved Fracture Treatments

Improved fracture-treatment designs can increase production rates from many reservoirs. However, do these changes merely accelerate recovery, or is incremental production gained by changing the fracture design? The authors re-examined three tight gas case studies published in the past 10 years. The original studies were performed specifically to assess the effects of increased fracture conductivity on production. In all cases, the initial analyses documented that increasing conductivity appeared to increase production and recovery.

Introduction

Since the first commercial hydraulic-fracture treatments in 1949, treatment designs have evolved from experimentation with massive hydraulic fractures to proppantless water-fracture treatments. While the production increase in the first few months or even the first year typically repays the cost of the conductivity upgrade, and is robust enough to make the decision to upgrade relatively simple, it is important to know whether this increase can be translated into additional ultimate recovery. If the ultimate recovery is also increased, then the economics of the completion upgrade may be even more favorable because it leads to a potential increase in reserves and drainage area per well, which in turn can lead to a reduction in the number of wells needed to drain the reservoir effectively.

In all cases, comparisons were made between high-quality ceramic proppants and either uncoated or resin-coated sand (RCS). In the past, conventional wisdom incorrectly suggested that hydraulic fractures in most tight gas wells behaved as "infinitely conductive." This misperception arose from a poor understanding of proppant performance under downhole (realistic) conditions. Under realistic conditions, all proppants should be expected to lose more than 90% of their effective conductivity. By reanalyzing these case studies with longer term production results, the authors sought to determine whether the original conclusions still hold true, and whether confidence in the recovery projections can be determined.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 144349, "Production Acceleration or Additional Recovery? A Look Back at Three Published Field Trials To Determine the Long-Term Benefits of Improved Fracture Treatments," by ***K. Blackwood,*** *SPE, Highmount Energy;* ***P. Handren,*** *SPE, Denbury Resources; and* ***M. Chapman,*** *SPE,* ***T. Palisch,*** *SPE, and* ***J. Godwin,*** *SPE, Carbo Ceramics, prepared for the 2011 SPE North American Unconventional Gas Conference & Exhibition, The Woodlands, Texas, 14–16 June. The paper has not been peer reviewed.*

East Texas Haynesville Lime Trial

A field trial was performed in the Haynesville lime of east Texas. The Haynesville lime in this area is a gas play just below the Cotton Valley trend and is Upper Jurassic in age. The Haynesville lime is 98–99% calcium carbonate, with net pay ranging from 50 to 90 ft. In the study area, the Haynesville-lime average reservoir parameters include depth of 11,500 ft, porosity of 8 to 12%, permeability of 0.2 md, and bottomhole shut-in pressure of 3,000 to 3,500 psi. The wells were drilled and originally completed between 1978 and 1982, with one well drilled in 2002. With the exception of the 2002 well, the wells were originally completed with 5,000-gal acid cleanup treatments evolving into crosslinked pad/acid and gelled-acid treatments, typically 60,000 gal. In the early 2000s, a program to restimulate the wells with propped hydraulic fractures was initiated. RCS was used in the initial fracture treatments. As the restimulation program evolved, it was recognized that the created fractures were conductivity limited because of the effects of multiphase and non-Darcy flow, reduced proppant concentration, and other downhole conditions. This led to the field trial that substituted a lightweight-ceramic (LWC) proppant for the RCS, to determine well-performance benefits of the additional conductivity.

At the time of the study and paper, nine LWC wells had been pumped, which were offsets to nine wells that used RCS. Each well pair was selected on the basis of what was hoped to be similar reservoir parameters. With the exception of proppant type, fracture-stimulation designs were kept as constant as practical to allow for a good head-to-head comparison.

Original Results. All wells in the study had an extended production-time period before the propped-fracture stimulation treatments, which enabled use of a fold-of-increase (FOI) analysis to determine the success of the treatments. This method allowed normalization of reservoir differences, such as net pay, permeability, and/or depletion. The initial post-fracture-treatment production was divided by the prefracture-treatment production to yield an FOI for each well. An average FOI of 3.6 and 4.8 for RCS and LWC, respectively, was reported. It was concluded that the use of high-conductivity proppant resulted in longer effective fracture half-lengths and, as a result, increased recoverable reserves for each well. An estimated ultimate recovery (EUR) was calculated with production-decline software to extrapolate both the before-fracture and after-fracture production rates. LWC wells were reported to provide a 42% increase in EUR over the unstimulated projection, and the RCS provided an 18% increase. While both proppant types showed positive economics from the fracture stimulation, the production increase by use of the higher-conductivity fractures resulted in a significantly higher rate and significantly higher recoverable reserves.

Update. At the time of the original study, the wells had been producing post-treatment for less than 1 year. Here, all wells have at least 7 years of post-treatment production. The updated analysis followed most of the same methods as the original study. After 7 years of actual production, the LWC wells produced approximately 9% more gas than an equivalent RCS well. After 30 years, the projected gas produced should increase by approximately 10%. Because the incremental gas is relatively constant between 7 and 30 years (approximately 9 to 10%), it appears that the recovered incremental gas comprises primarily additional reserves rather than accelerated production. It appears that, if anything, the incremental recovery may be increasing over time.

West Texas Canyon Sand Trial

This field trial compared the performance of high- and low-conductivity fractures in the Canyon sand formation in the Sonora field of Sutton County, Texas. The trial was initiated in 2006 after modeling suggested that the existing fractures were providing insufficient conductivity. At that time, all of the 21 wells in the trial, including 10 economy-lightweight-ceramic (ELWC) -proppant and 11 offset Brady-sand-proppant wells, had at least 1 year of production.

The Canyon sands in the Sonora field are Lower Wolfcampain and are fine- to medium-grain quartz lithic arenites deposited in a series of deep-water slope-fan deposits in a wedge-shaped interval that creates highly variable thickness. Reservoir properties vary across the field, but typically are 6,500-ft depth, 1,500-ft gross sand thickness, and 0.01- to 0.001-md permeability. The wells are logged open hole, and reservoir quality generally is described with porosity-feet (ϕh) correlations. Typically, these vertical wells were fracture stimulated with 4–6 stages with a low-pH crosslinked-fluid system and 40-quality CO_2 foam at 40 bbl/min. Most stages were designed for approximately 80,000 lbm of proppant (approximately 400,000 lbm/well) at maximum concentrations of 5 to 6 lbm of proppant added per gallon of clean treatment fluid (PPA). Fracture modeling suggested that these completions had restricted conductivity because of non-Darcy- and multiphase-flow effects, reduced fracture width, and gel damage.

Original Results. The original analysis was performed after most wells had approximately 1 year of production. Production was analyzed two ways—use of raw production data and use of production data normalized for the difference in reservoir quality, as determined with the ϕh correlations. Normalized results showed an average increase in average first-30-days production of 60% for the ELWC wells and 40% increased production during the first year. Decline-curve analysis was performed with the average first-year production for each completion type, and, while percentages were not given, the incremental gas produced after 30 years was projected to be 135 MMcf for the high-conductivity fractures compared with low-conductivity fractures.

Update. Here, all wells have more than 3 years' production. The individual wells showed reasonably good production profiles for the first 2 years' production. However, because of the low gas rates and significant liquid production (condensate and water), the production after 2 years from approximately one-third of the wells began to exhibit fluid slugging and, in some cases, many days or even weeks of shut-in production. To account for some of this shut-in period, all of the "zero" production days were effectively removed from the data. While this phenomenon occurs in some wells in both sets of data, caution must be used when viewing the long-term results, particularly when making decline-curve projections.

After removing the zero production and normalizing for ϕh, a comparison of average cumulative production was made for each set of wells. The ELWC wells produced an average of 20% more gas during the first 1,000 days than the offset Brady-proppant wells. While still a significant increase, on a percentage basis, this increase is substantially less than the 1-year increase of 40% presented in the original study.

Decline-curve analysis was performed on each set of wells using the actual 1,000-day average production. In both sets of wells, the best match was obtained with hyperbolic decline. These decline curves then were used to estimate the gas recovered at similar points in the future; in this case, 20 years was used as the arbitrary cutoff. After 20 years of normalized production, the decline-curve analysis suggested that the ELWC wells would produce an incremental 16 MMcf of gas more than the Brady-proppant wells, or 8% incremental production. Because this is 3 MMcf less than the incremental production after 1,000 days, the analysis suggests that at least some of the incremental production from the ELWC wells could be attributed to accelerated production vs. additional recovery. In the case of this trial, the amount of additional recovery will be contingent upon how long the wells produce. At 20 years, it appears that the additional recovery will be approximately 8% per well. If the wells are produced longer, then this value will likely decrease.

East Texas Cotton Valley-Taylor

A study of the Cotton Valley Group in the east Texas Minden field, in Rusk County, focuses on the basal portion of the group called the Taylor sand, bound by the Bossier shale below and the Taylor lime above. In the study area, the Taylor sand has a gross thickness of 250 ft, porosity range of 7 to 14%, 32% average water saturation, and permeability estimated between 0.04 and 0.1 md. The Taylor sand is considered a tight gas sandstone.

Drilling began targeting the Cotton Valley sands in the late 1970s, and effective hydraulic fracturing has contributed greatly to the success of those wells. Stimulation techniques evolved from crosslinked-gel treatments in the 1980s, placing massive volumes of proppant (>1,000,000 lbm) at high concentration (10 PPA or higher), to slickwater-fracture treatments in the 1990s that were believed to be successful because they were less damaging to the formation. The downside of slickwater fracturing is poor proppant transportation, which, at the time, limited treatments to an average proppant concentration of 1.0 PPA or less. This poor transport, coupled with the apparent narrow hydraulic-fracture width, led many operators to pump small-mesh (40/70 and occasionally 30/50) uncoated sand and RCS as proppant. Similar to other cases, most operators erroneously presumed that they had "enough" conductivity for these completions.

However, the original study investigated the conductivities of those proppants, and it was realized that under the realistic downhole conditions, the fractures had restricted conductivity that was caused primarily by the non-Darcy- and multiphase-flow reductions that result from concurrent condensate production and from the narrow fracture widths generated by the slickwater-fluid system. After replacing the 40/70- and 30/50-mesh RCS with 30/50- and 20/40-mesh ELWC, the acquired knowledge of proppant transport in slickwater fractures (i.e., the first proppant placed is likely closest to the wellbore) was used to implement a technique in which a portion of the higher-conductivity larger-diameter proppant (20/40-mesh ELWC) was pumped first, followed by 30/50-mesh ELWC, followed by the remaining 20/40-mesh ELWC. The primary driver in these design modifications was recognition that any increases in conductivity, particularly near the wellbore, should increase production from the well.

Original Results. Five wells were treated with some combination of 30/50- and 20/40-mesh ELWC. All used slickwater as the primary fracture fluid, with 20-lbm/1,000-lbm linear gel used to place the 20/40-mesh proppant (to assist in proppant transport and hydraulic-fracture width). These wells were compared with 20 offset wells that contained a combination of uncoated sand and RCS. The average initial production of the five high-conductivity wells was 1.75 MMcf/D, compared with the offset-well average of 1.45 MMcf/D. In addition, the highest-initial-production well was one that used the design in which 20/40-mesh ELWC was pumped first. After 180 days, the high-conductivity wells averaged 138 MMcf per well and the offset wells averaged only 123 MMcf. While the offset wells had a large amount of historical production, only 180 days of production was available for this study. Also, it was reported that the EUR projection for the offset wells was approximately 1 Bcf/well, while the five high-conductivity wells projected an EUR of 1.3 Bcf/well, an incremental 0.3 Bcf/well (i.e., 30% increase). Along with the gas increase, there was a reported corresponding increase in condensate rate and condensate yield.

Update. Here, all wells in the case study have at least 48 months of production history. Actual production was compared for the first 4 years for both sets of wells using data obtained from public databases. After 4 years, the five wells receiving ELWC had produced an average of 433 MMcf of gas, while the offset wells produced an average of 399 MMcf, an increase of 34 MMcf (9%) over the 4-year period.

Decline-curve analysis was used to project production from the 48 months of data for both sets of wells. Again, hyperbolic decline appeared to provide the best fit through the data. In this case, 20-year recovery projections were made, and the results showed an incremental 100 MMcf/well of gas production for the wells that received ELWC, compared with the offset wells that received uncoated sand or RCS. The original study suggested a calculated incremental EUR of 300 MMcf/well of gas (30% increase) for the ELWC wells vs. the RCS wells. The length of time and economic cutoff used in the original study are unknown, so it is difficult to compare the update. However, because this update showed an incremental recovery of 15% and 100 MMcf/well after 20 years, it is likely that the recovery will not increase to the 30% and 300 MMcf from the original work.

Note that in this case, the incremental recovery is projected to increase over time (from 9% after 4 years to more than 15% after 20 years). This suggests that the incremental production created with the higher-conductivity proppant likely consists primarily of additional recovery rather than accelerated production. **JPT**