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Approach Optimizes Completion Design

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THE WOODLANDS, TX.–Horizontal wells drilled in the northeast part of the Eagle Ford Shale play in the DeWitt County, Tx., region require a reservoir-specific completion strategy. Production in this part of the Eagle Ford has high liquid-to-gas ratios, and core analysis shows a low Young's modulus (soft rock) and high clay content. These and other factors present different challenges to hydraulic fracturing than the high-rate water frac completions typically associated with dry gas shale stimulation treatments.

GeoSouthern Energy Corp. had participated in several horizontal Eagle Ford Shale wells in DeWitt County that were completed using Barnett Shale-style high-rate water fracs and the results generally had been disappointing. It was clear that higher-conductivity fractures were needed for the liquids-rich multiphase hydrocarbon production, and that swelling clays and proppant embedment issues would have to be considered, but improving the completion design in this part of the Eagle Ford play required answering several unknowns.

To address issues such as determining the optimal number of frac stages per lateral, proppant type and mesh size, volumes of proppant pumped on each stage, the perforation scheme, completion fluid type, and injection rates, GeoSouthern Energy has taken a collaborative "applied science" approach to Eagle Ford completion design. This includes applying both a geologic and reservoir understanding of the nano-Darcy formation to optimize stimulation treatments.

Petrophysical analysis is the key to understanding the reservoir. Unfortunately, the data required for good reservoir analysis do not always exist, especially in a relatively new play such as the Eagle Ford. Assessing experiences in similar reservoirs is a good place to start climbing the learning curve, but there are enough subtle differences between different shale reservoirs that a one-size-fits-all approach is probably inadequate. When data are available, the next step is to try to develop correlations, with some degree of confidence, to aid in the completion design.

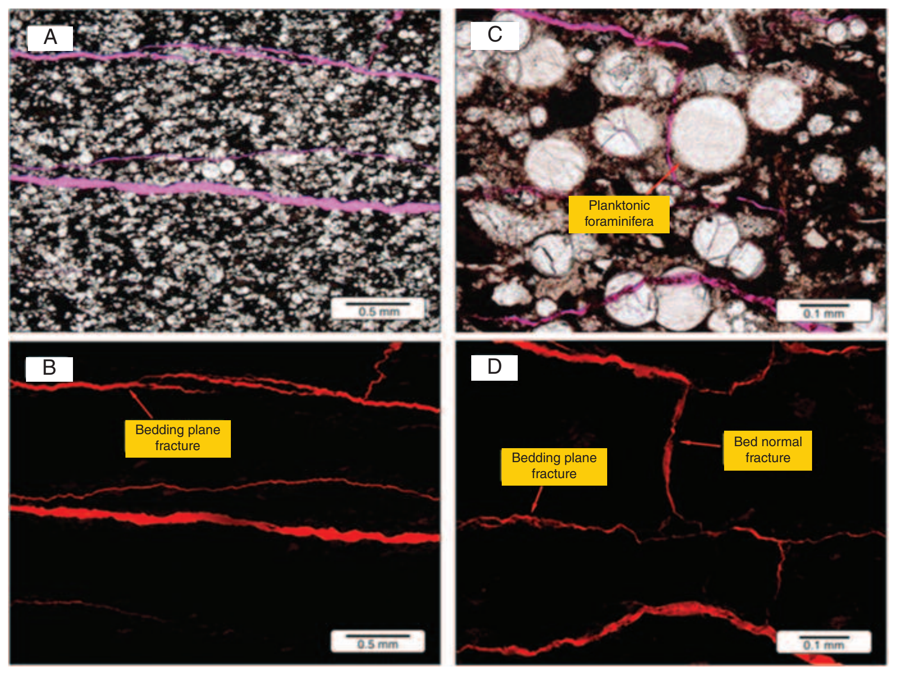
In addition to conventional reservoir properties (porosity, resistivity, water saturation, permeability, pore pressure, mechanical rock properties, etc.), shale characteristics such as brittleness, ductility, complexity, mineralogy and laminations also need to be understood. A more complete reservoir characterization provides the asset team with knowledge to design the best completion for the well.

Reservoir Understanding

The characteristics of the Eagle Ford change substantially across the southwest-to-northeast strike of the play. Shale thickness ranges from 45 feet in the Austin area to more than 500 feet in the dark shales that outcrop in Dallas County, and true vertical depths range from 2,500 to 13,000 feet. Pressure gradients, total organic content and mineralogy also vary significantly. To further complicate this

FIGURE 1

Normal and Bedding Plane Fractures from Eagle Ford Cores



technically challenging play, many reservoir characteristics can change significantly over relatively short distances. Consequently, understanding local regional characteristics is critical to commercial development.

Eagle Ford development began as a shale gas play in LaSalle County (in the southwest part of the play) in late 2008. Not surprisingly, the first stimulation designs were slick-water fracs patterned after what had been done in the Barnett. However, the reservoir properties of the Eagle Ford are substantially different. While the Barnett is a very brittle gas-bearing siltstone with a high Young's modulus, the Eagle Ford produces both gas and high-gravity oil, and is mainly a clay-rich limestone with very low quartz content. This tends to make it less brittle (more ductile), with a low Young's modulus.

Whole core testing indicates that because the rock is relatively soft (low Young's modulus), it is prone to proppant embedment. While the Barnett Shale has about 0.20 grain diameters of embedment at 5,000 psi closure stress, the Eagle Ford can have an entire grain diameter of embedment at 10,000-psi closure stress. Embedment tests were conducted on Eagle Ford core to validate simulations.

In addition, the Barnett has little, if any, stress anisotropy (the difference between the maximum and minimum horizontal rock stress). This allows a complex network of fractures to be created rather easily using a low-viscosity stimulation fluid in the hard, brittle and highly naturally fractured formation. Under these reservoir conditions, slick water fracs with low volumes of fine-mesh proppant have been effective.

The softer, more ductile Eagle Ford potentially can have more stress anisotropy, which allows for more planar-type fractures. Higher concentrations of larger-mesh proppant placed with a hybrid fluid system provide the conductivity to overcome embedment and multiphase flow. Eagle Ford cores may not have a lot of visible natural fractures, but microfractures can be present (Figure 1), which means a balance of net pressure may be required to maintain small fracture offsets along weak bedding planes and fissures during stimulation. A proper design rate and fluid viscosity is required to create dominant fractures at the well bore and establish the necessary fracture width while remaining in the pay interval.

Whole core data had been taken through the Eagle Ford formation while drilling a vertical offset well and a relatively complete core analysis had been performed, so the team had good rock and reservoir data from x-ray diffraction (XRD), geomechanical testing, embedment tests, total organic content determination, desorption analysis, and pressure/volume/temperature analysis.

On the subject well in DeWitt County, a vertical pilot hole was drilled and open-hole electric logs were run across the formation. The vertical section was plugged back, the lateral section was drilled, and production casing was cemented in place. A mud log (gamma ray, rate of penetration and total gas) provided the only data available in the lateral section.

FIGURE 2

Offset Well Calibrated to Core Data

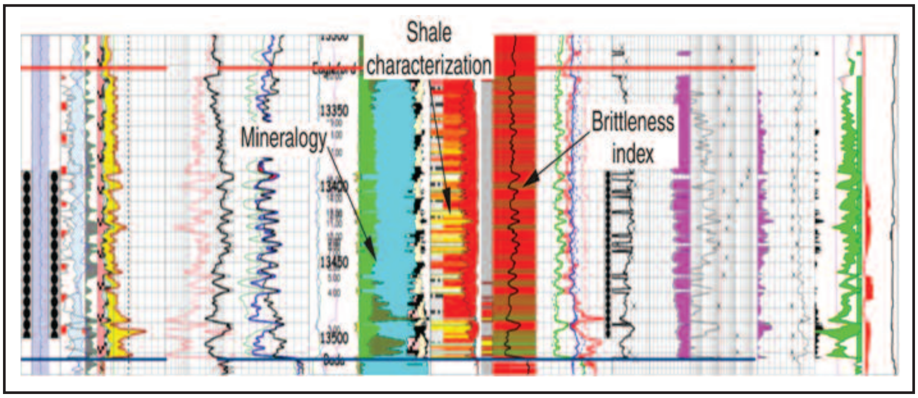


TABLE 1

Summary of Reservoir Properties from Core Data Analysis

	MINIMUM	MAXIMUM
TOC (%)	2	6
Porosity (%)	8	18
Water saturation (%)	7	31
Permeability (nD)	1	800
Young's modulus (psi)	1.00E+06	2.00E+06
Poisson's ratio	0.25	0.27

Petrophysical Analysis

Electrical log, core and mud log data from an offset vertical well were analyzed to develop an accurate petrophysical model to characterize the Eagle Ford in the area. The model then could be applied to other wells in the DeWitt County region to aid in developing a completion strategy based on actual petrophysical characteristics.

The organic-rich shale was identified using spectral gamma ray electric log data, which also were used for clay typing. Other conventional logs were used for mineral identification, which is critical to completion design, especially in regard to fluid effects on the formation (photoelectric absorption for pyrite volume, bulk density for limestone volume, neutron porosity for clay volume and porosity, and resistivity for water saturation). The sonic logs, together with multiple other petrophysical relationships where both mineralogy and shale type were considered, were used to calculate rock properties (Poisson's ratio and Young's modulus), which were then calibrated to both dipole sonic data and core data.

Image logs showed the Eagle Ford in DeWitt County to be a finely laminated shale with bedding planes, all with dip angles of less than 10 degrees, indicative of a low-energy depositional environment with azimuth primarily south-to-southeast. Fractures, faults and folds were not discernable in this part of the play.

In addition, the shale log model was used to calculate total organic content, kerogen content, free-gas volume and the rock brittleness factor, thereby grading the shale reservoir into potential completion intervals. The log-generated stress profile and rock properties were used to simulate sensitivity to frac rate and fluid type.

The shale brittleness factor, mineralogy and shale classification analysis (Figure 2) were used in a frac simulator to model laminations and bedding planes. This was incorporated into the frac model to simulate any bounding layer properties that could affect fracture height growth. Closure pressure and embedment test data were used to select the proppant type and mesh size. Finally, the mud log in the vertical pilot was reviewed to see the extent of any hydrocarbon shows.

Calibrating The Model

After evaluating the logs, the model was calibrated using core data. This is a critical component of the analysis, because log interpretations can be inaccurate without measured core data. Table 1 summarizes reservoir properties from core data analysis. The entire petrophysical analysis process looped around between log and core data and back to logs, validating an accurate petrophysical model of the area. The mineralogy derived from the logs was calibrated to the XRD analysis mineralogy, and both were used to tailor the frac fluids used for the completion.

Core geochemistry identified the kerogen type and maturity to be in the mature oil window, with some core in the condensate wet gas window with fair hydrocarbon potential. Therefore, the completion design needed to focus on an oil-producing shale rather than dry gas, unlike early Eagle Ford wells. Fluid sensitivity and proppant embedment tests were conducted on the core and the findings were used in the stimulation design.

Thin sections of the core characterized the Eagle Ford shale visually as a planar laminated shale with numerous bedding plane fractures, planktonic foraminifera, and an organic-rich matrix. Occasional bedding normal fractures and pressure-release fractures were observed. Whole core indicated that the overburden stress was normal. This information was used in the completion strategy because the potential existed for the swelling clays identified by XRD and the log to plug the fractures. No fractures were seen by the open-hole image log, but that is not uncommon for shale reservoirs.

After calibrating the offset well to core data, the petrophysical model was applied, and the vertical pilot hole was drilled, logged and plugged back before drilling horizontally through the Eagle Ford. Because cased-hole pulse neutron log data were not acquired in the lateral to generate a synthetic open-hole log for petrophysical analysis, the petrophysical analysis from the vertical pilot hole was transposed to the horizontal section to create pseudo gamma ray and shale log analyses of the lateral.

Figure 3 shows that the pseudo gamma ray (black solid line) correlated well with the actual measured mud log gamma ray (red line with green shading), illustrating that the technique in the deviated (>45

FIGURE 3

TVD-Measured Gamma Ray Versus Pseudo Gamma Ray

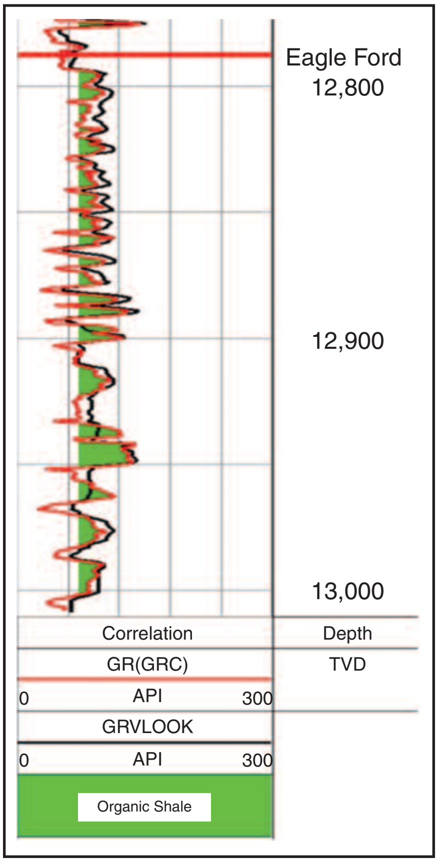


FIGURE 4A

Pseudo Shale Log Brittleness from Transposing Vertical Pilot Shale Log Data to Lateral

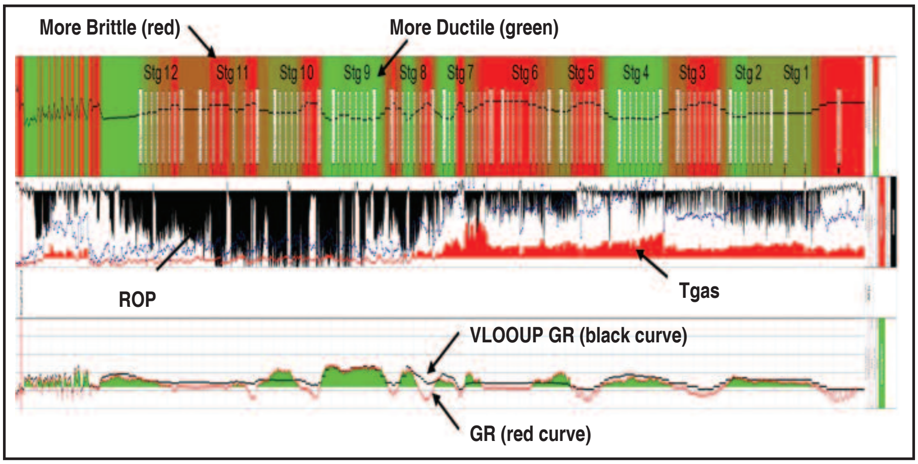


FIGURE 4B

Reservoir Dip and Directional Drilling Data in Lateral

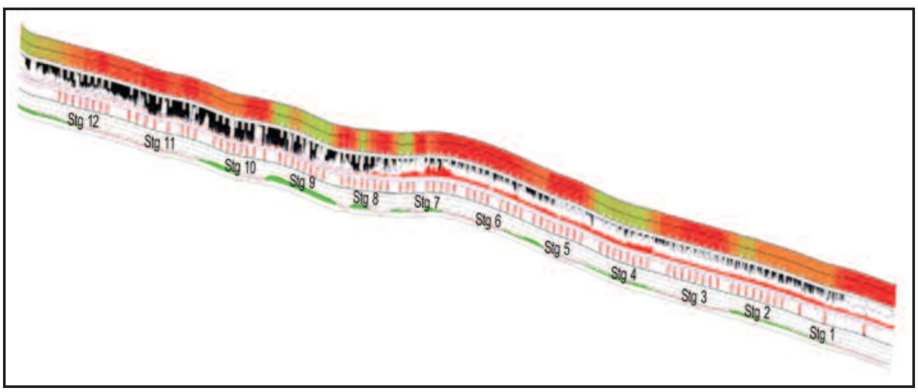
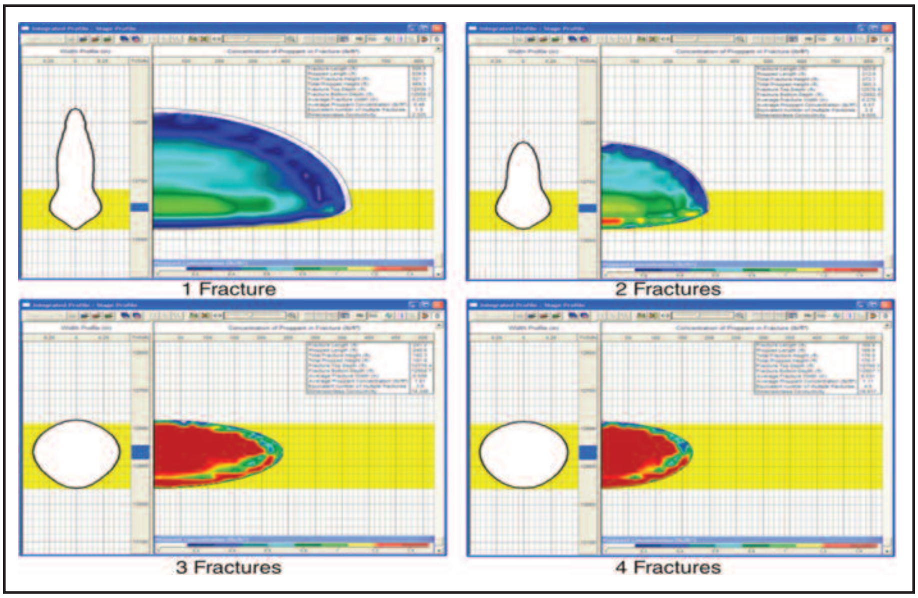


FIGURE 5

Fracture Sensitivity Simulations for Single Stage



degree) well bore matched the vertical pilot well bore at the top of the Eagle Ford formation. Figure 4A shows the entire transposed pseudo shale log analysis in the lateral. This provided valuable information (brittleness factor, stress, Poisson's Ratio, Young's modulus), which was used in conjunction with the mud log hydrocarbon shows to determine the number of frac stages and where to place the perforation clusters in each stage.

The pseudo shale log helped identify the organic-rich shale, select the completion intervals by indicting rock with higher brittleness, and place perforation clusters in completion intervals with similar stresses. Figure 4B illustrates the actual lateral well bore with reservoir dip and directional drilling data included. In some places (stages 2, 4, 9 and 11), the pseudo gamma ray matched the mud log very well, while there was not such a clear correlation in other parts of the well. In stages 2, 4 and 9, the brittleness factor shows a ductile rock, and higher treating pressures were observed and the stages were harder to complete. In the more brittle rock (stages 3, 5, 6, 7, 8 and 11), it was easier to execute the stimulation plan and normal treating pressures were observed.

Completion Design

Formation evaluation was a vital part of the completion design. Some of the data in the shale log analysis were used qualitatively (mineralogy, shale classification, total organic content, brittleness index, etc.), while other parameters were used quantitatively (stress, Poisson's Ratio, Young's modulus, bottom-hole pressure, etc.) to design the treatment. Formation evaluation for a shale reservoir requires a different mindset because it is not a conventional porosity/permeability reservoir. This also applies to completion design.

The well bore configuration was 15.1-pound/foot, 4 ½-inch casing with a tieback in the top of a liner at ≈11,200 feet (≈13,250 feet TVD of the formation). The measured depth of the well was 16,500 feet with a 3,800-foot lateral. The well bore was drilled in a northwest-to-southeast direction to intersect transverse fractures. The fracture simulator was populated with rock properties and reservoir data obtained from the petrophysical analysis in the vertical pilot. The hybrid frac pump schedule was input and sensitivities were run for pump rate, viscosity and number of fractures generated in the horizontal section based on number of perforation clusters.

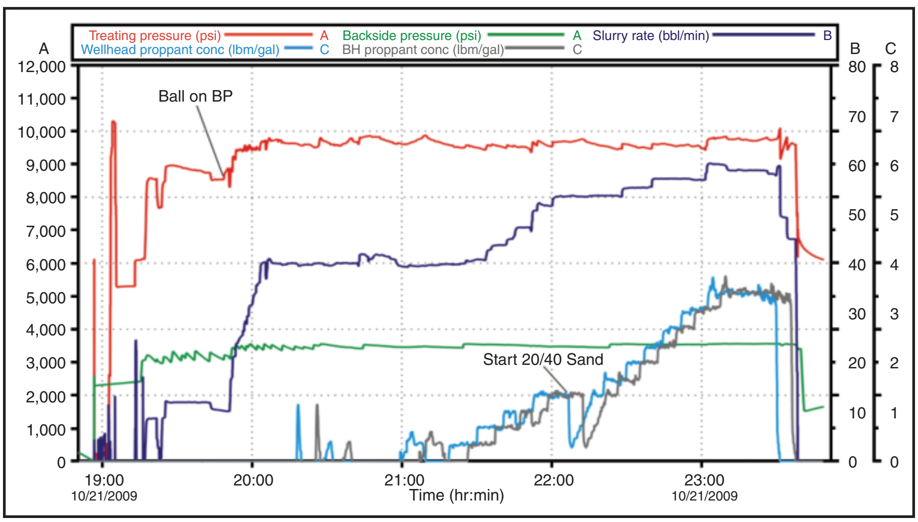
This exercise also helped determine how much lateral interval might be effectively stimulated with each frac stage. The initial hybrid stimulation was designed so that the cross-linked portion would transport proppant for approximately 60 minutes, with the cross-linked fluid maintaining a high viscosity for 15 minutes. The intent was to create fracture geometry with viscosity, rather than rate, to effectively stimulate each frac interval and keep fractures in the pay zone. The fluid would be allowed to degrade, both with temperature and high-temperature breakers, to low viscosity to maximize the potential stimulated reservoir volume.

The fracture simulations (Figure 5) were based on a single stage with four perforation clusters. The model was set to equally distribute the fluid and proppant between the perforation clusters to create four fractures. The goal was to achieve a ≈1 pound/square foot proppant concentration to handle the high expected liquid production.

The simulation results showed that if only one perf cluster took fluid, a single, 450-foot long fracture would be generated that would grow into the Austin Chalk and have very low conductivity. The results were a little better if two clusters took fluid, but both created fractures also tended to grow out of zone. The effective propped length of each frac was only 150 feet and conductivity was low. If three fractures were generated, the fracs would stay contained within the Eagle Ford and achieve an effective propped frac length of 200 feet (600 feet net). Conductivity was doubled and distributed evenly across the formation. If four fractures were created, each frac would generate 125 feet of effective propped frac length (500 feet net)

FIGURE 6

Stage 2 Treatment Plot



with good conductivity.

Perforation Design

Because it is impossible to determine how many perforations actually will break down and take fluid/proppant, multiple methods were incorporated to enhance the chance of success. The first method was based on limited-entry perforating. An injection rate of 45 bbl/minute was selected partially because of wellhead pressure limitations (10,000 psi wellhead). Subsequent treatments have incorporated a 15,000-psi wellhead to increase the safe surface working pressure. Perforating a total of 36, 0.34-inch diameter holes at 60-degree phasing with a 45 bbl/minute liquid rate generates ≈500 psi perforation friction, assuming 30 percent of the holes do not take fluid. An injection rate of 30 bbl/minute still creates ≈500-psi perforation friction if only 25 holes are open. The plan was to shoot four, two-foot clusters with six shots per foot (12 holes).

The second method used the petrophysical analysis results to place the perforation clusters for each stage in "like" rock, theorizing that if the reservoir rock near the well bore is the same, it should have very similar breakdown pressures. The perforation scheme for each stage targeted more brittle rock and tried to avoid the ductile areas. This might seem like a very subtle detail, but once a fracture initiates in an interval, it can be difficult to break down the other clusters.

Core XRD analysis showed an average total clay content of ≈20 percent, with about half of it being mixed-layer clay. Cores also indicated normal and bedding-plane fractures that could become plugged with swollen clays, greatly impeding hydrocarbon production and ultimate recovery. Six percent sodium chloride was added to the completion fluids for clay control, and fluid compatibility testing determined that a nonemulsifying surfactant should be used.

Proppant-embedment testing on Eagle Ford core samples showed embedment in the range of 300-700 microns in depth at 10,000 psi with high-strength proppant. This means low concentrations of small proppant can actually "disappear" into the formation face and propped-fracture conductivity can quickly approach zero. Consequently, the treatment required larger-mesh (30/50 and 20/40) proppants. Because the well was expected to produce liquid hydrocarbons, higher concentrations of larger-mesh proppant were needed to achieve the required fracture conductivity.

Proppant embedment, proppant crushing and formation fines migration are major components that can cause the loss of fracture conductivity over time. Proppant diagenesis also can degrade the conductivity of a proppant pack, especially at elevated temperatures (the bottom-hole temperature in the subject well was calculated at 327 degrees Fahrenheit).

The economics were reviewed, and the decision was made to pump natural sand at the beginning of the job, followed by premium resin-coated proppant (RCP). The split was 15 percent 30/50-mesh premium white sand, 35 percent 20/40-mesh premium white sand, and 50 percent 20/40-mesh premium RCP (white sand substrate). A surface-modifying agent was recommended for all the uncoated premium white sand to minimize conductivity-degradation effects.

Job Execution

The first stage was perforated with a tubing-conveyed gun. Miscommunication

FIGURE 7A

Stage 11 Treatment Plot

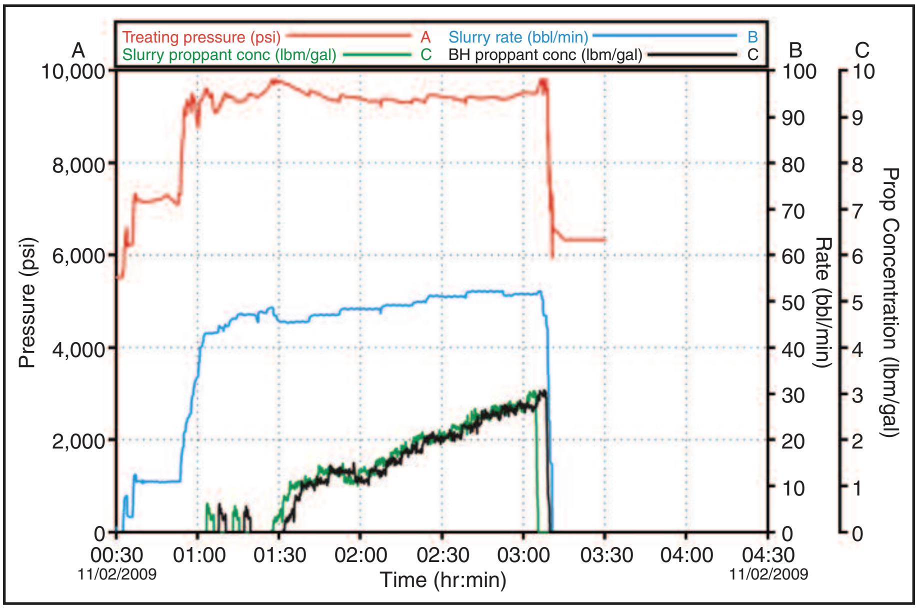


FIGURE 7B

Stage 9 Treatment Plot

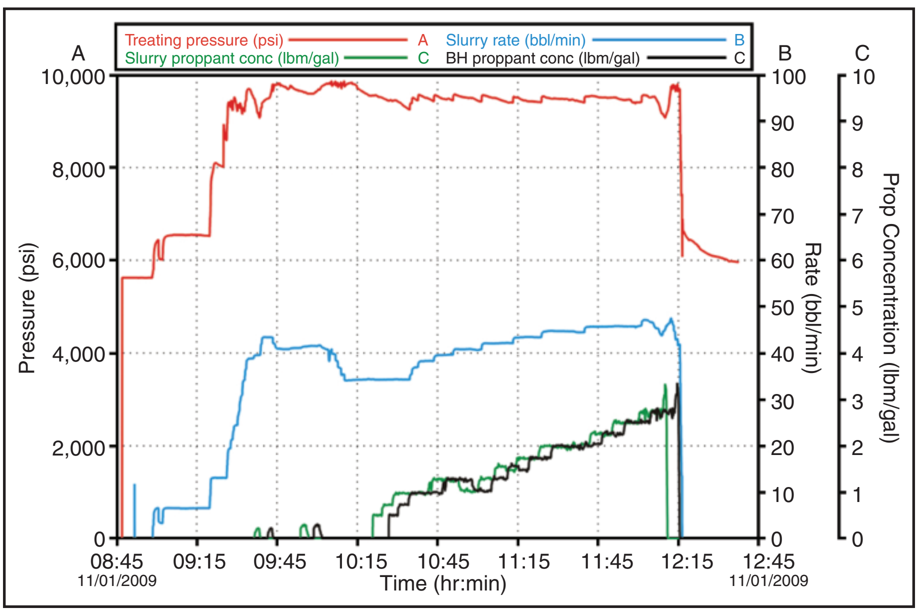
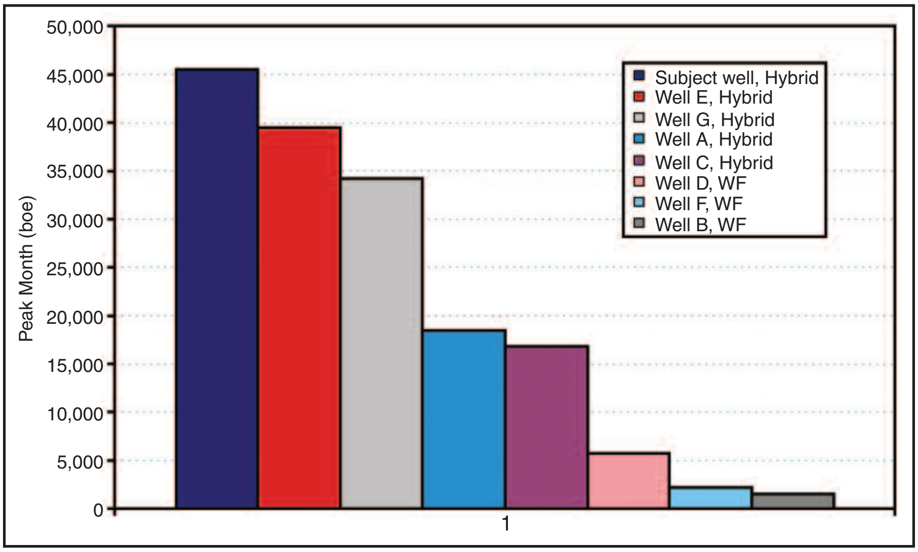


FIGURE 8

Monthly Peak Production Comparison



resulted in a 10-foot long perforated interval at the toe of the horizontal. Two, three-foot long clusters were added for a total of 96 holes across 16 feet, which was not the ideal configuration. The toe of a horizontal is routinely the hardest to frac, and this well was no exception. The injection rate was less than 20 bbl/minute at 9,800 psi. Almost three hours were spent attempting to obtain sufficient fracturing injection rate without success before finally deciding to reperforate the first stage.

The injection rate was a little better (25 bbl/minute at 9,900 psi). Various approaches were attempted to get a good break down (viscous gel slugs, 100-mesh proppant slugs, etc.), but near-well-bore friction was too great to overcome (a step-down test indicated more than 1,500 psi of near-well-bore friction). Wellhead pressure increased each time a 1,000-gallon stage of 100-mesh proppant was pumped, and cross-linked slugs displaced with linear gel seemed to reduce wellhead pressure better than proppant slugs. Because the maximum allowable wellhead pressure limit of 10,000 psi was almost reached, stage 1 was abandoned and operations moved to stage 2.

To ensure there were enough holes in the casing, the perforation scheme was redesigned for eight, one-foot clusters with six shots per foot at 60 degree phasing (48 holes per stage). After the difficulty and lessons learned on the first stage, 30/50-mesh proppant was used for the initial slugs instead of 100-mesh (Figure 6). The bridge plug ball was dropped in the first 20 barrels of acid (total of 120 barrels of acid per stage) and displaced with linear gel. After the ball landed and the injection rate increased to 30 bbl/minute, cross-linked proppant slugs were pumped.

Again, each time the proppant slug reached the formation, pressure initially increased and then gradually declined. A stable 30-bbl/minute injection rate on the pad fluid was obtained with cross-linked gel, so it was decided to start pumping 30/50-mesh proppant. The concentrations were increased slowly from 0.25 to 1.0 pound/gallon, one well bore volume at a time. When the 20/40-mesh proppant was started, the concentration was decreased to 0.25 pound/gallon and slowly ramped to 1.0 pound/gallon to make sure there were no well bore width issues and the proppant could be placed. This on-the-fly redesign process continued until

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a concentration of 2.5 pounds/gallon was achieved. A total of 300,000 pounds of proppant was placed in 7,900 barrels of fluid.

Treatment Results

The subsequent nine stages were completed in a similar fashion. The redesigned pump schedule consisted of more linear and cross-linked gel to better place proppant in the formation than low-viscosity fluids. Also, a constant injection rate was maintained throughout the majority of the job instead of using a variable rate (slowing when switching to cross-linked fluid). Proppant concentration was reduced by only 0.5 pound/gallon when switching from 30/50- to 20/40-mesh proppant, once experience was gained.

The stages that were easier to break down and establish injection early in the job used less fluid to place the designed proppant volume than the intervals where it was harder to establish injection. Stages 2, 4 and 9 were the most difficult to pump. Both stages 9 (more ductile) and 11 (more brittle) correlated well to the transposed horizontal shale log and are examples of the benefits of knowing the brittleness index of the rock in the lateral section and how it relates to treatment.

Figures 7A and 7B illustrate how stage 11 established injection without difficulty and the design rate was easily achieved (total pump time was about two hours). Stage 9, on the other hand, experienced difficulty in getting injection established and had a difficult time achieving the designed pump rate (total pump time was about three hours).

Coiled tubing was used to drill out the bridge plugs and clean the well bore. The flow-back choke size was slowly increased by 1⁄64 inch until a 14⁄64-inch choke was installed about two weeks into flow back. After 60 days, the well was flowing on a 20⁄64-inch choke and had produced more than 50,000 barrels of oil and 150 million cubic feet of gas. About 10 percent of the frac load water was recovered after 180 days, and the well was producing only 10 barrels of water a day.

The production on this tailored hybrid completion far exceeded the production of offset slick-water completions. Figure 8 shows the well's peak production compared with seven offset Eagle Ford completions treated with slick water or hybrid fracs in DeWitt County as well as adjacent Gonzales and Karnes counties. In general, hybrid treatments appear to outperform water frac treatments. This is likely because of the higher fracture conductivity achieved with a hybrid treatment, allowing a more unrestricted flow path for the liquids. ❐