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Advanced Completion Design, Fracture Modeling Technologies Optimize Eagle Ford Performance

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HOUSTON–Unconventional resources require fracture stimulation to achieve economic production rates and recoveries. However, hydraulic fracture modeling in resource plays, specifically in the Eagle Ford Shale, is challenging and often reduced to "rules of thumb" and design concepts taken from other shale plays. Although there is a place for extrapolating best practices to the Eagle Ford from other reservoirs, the calcareous makeup of the rock, the complex geology and condensate-rich environment present unique completion challenges.

Furthermore, concepts of pressure-dependent leakoff, process zone stress, hoop stress, stress-dependent Young's modulus, and complex fracture propagation limit confidence in traditional fracture models, and can result in early job terminations and less-than-optimal fracture stimulations. These challenges require a hydraulic fracture model and treatment design tailored specifically to the Eagle Ford.

To optimize hydraulic fracture design in the Eagle Ford, one study applied a first-order discrete fracture network (DFN) model to predict fracture geometry. In addition, an approximate analytical production solution for multiple finite conductivity for vertical transverse fractures was used to production history match the well flow streams for DFN calibration and to aid in fracture optimization. Fracture length, conductivity and spacing for multicluster, multistage completions along the horizontal well bore were varied to illustrate the impact of improved hydraulic fracture design on well production and the effect of fracture interference on the resulting geometries and production.

The advantage of using a DFN technology for hydraulic fracture design in the Eagle Ford Shale is the ability to model complex fracture behavior that may better predict fracture geometry. The results illustrate the impact of varying fracture/completion design, including the effects of stage and perforation cluster number and spacing, as well as fracture length and proppant pack conductivity for a dry gas well (Well A) and a condensate-rich well (Well B). The treatment and production data, fracture diagnostics and microseismic results provide insights on how sound engineering and fracture modeling can increase recovery and optimize completions in the Eagle Ford play.

Fracture Modeling

Multiple frac stages and multiple clusters per stage along the length of the horizontal well bore create multiple transverse fractures (perpendicular to the horizontal well bore), which influence both initial production rates and production declines. One of the challenges of fracture modeling in unconventional formations such as the Eagle Ford is that traditional biwing fractures simulators grossly misrepresent actual fracture geometries. Fracture models are an important component of optimizing hydraulic fracture designs for parameters such as fracture conductivity, effective half-length and stage/cluster spacing, but it is critical to recognize this limitation with traditional biwing simulations.

Discrete fracture network modeling is one component of a methodology that can be used to improve a completion and stimulation program for enhanced shale production. Well performance can be improved by combining microseismic monitoring, production and radioactive logs, and production history matching with DFN fracture modeling and fracture conductivity enhancement. Economics then can be run to determine net present value and discounted return on investment for various fracture designs and flow streams, leading to improved decision making.

The concept of fracture conductivity often is overlooked as a stimulation design variable in shale plays. The presence of nano-Darcy rock does not necessarily intuitively lead to the need for higher conductivity. However, while the fracture conductivity required to economically produce a horizontal well in an unconventional reservoir and improve hydrocarbon recovery varies for different shale plays, the primary issue is that many reservoir engineers do not fully appreciate the impact of placing proppant in realistic downhole conditions. The proppant pack conductivity for a selected proppant is a function of particle size, strength, grain shape, embedment into the formation rock, cleanliness/residue of the fracturing fluid, fines migration, closure stress and fluid flow effects.

When accounting for these effects, proppant pack conductivity can be reduced by two orders of magnitude. One of the primary reductions is related to nonDarcy and multiphase flow effects, which are well documented in the industry. In addition to these flow effects, incremental reductions for gel damage (even from friction reducers) and proppant embedment can result in fracture conductivity values of 1 to 10 percent of published values. Given the reservoir characteristics for the Eagle Ford formation in both the dry gas and condensate producing wells, ceramic proppants were used in both wells to investigate the impact of higher frac conductivity on productivity.

Eagle Ford Geology

The Eagle Ford formation is a widespread Upper Cretaceous deposit that has long been known as a source rock for other plays in Texas, yet only recently recognized as an unconventional oil and gas play. In South Texas, the Eagle Ford is between 5,000 and 13,000 feet below the surface with thickness ranging from 50 to 300 feet. The Eagle Ford Shale actually is composed of organic-rich calcareous mudstones and chalks that were deposited during two transgressive sequences: the upper and lower Eagle Ford. The makeup of this rock makes the play significantly different than other unconventional plays such as the Barnett, Haynesville and Marcellus, all of which are found in primarily siliceous environments.

The Eagle Ford overlies the Buda Limestone and is deposited as low-angle strata primarily on a gently sloping ramp. The lack of benthic fossils or burrows suggests that the sediments were deposited in an oxygen-deficient basin, which is a necessary condition for preserving organic matter and hydrocarbon formation. The organic richness in the Eagle Ford typically decreases higher in the section, most likely because of a more oxygenated environment at shallower depths. Therefore, the lower Eagle Ford tends to be more organically rich and produces more hydrocarbons. Total organic carbon in the Eagle Ford ranges from 1-7 percent.

The Eagle Ford is overlain by the Austin Chalk, which was deposited in shallower water depths, and consequently does not have the same organic-rich qualities. The Austin Chalk does have excellent reservoir characteristics, particularly where it has been fractured, and hydrocarbons found within it are sourced by the Eagle Ford.

Because of its widespread regional scale, the Eagle Ford consists of several subplays. In La Salle County, a sweet spot has been identified between the Edwards Shelf edge and the Sligo Shelf edge. The difference in the location of these paleo-shelf edges has effectively created a “minibasin” where the Eagle Ford accumulated in thick deposits in an oxygen-deficient environment. The burial depth in this area (10,000-13,000 feet) has resulted in wells that produce large quantities of dry gas.

To the northwest, in the Maverick Basin, the Eagle Ford is much shallower at 5,000-8,500 feet. The Maverick Basin provides an ideal depositional environment for the Eagle Ford, but because of its location further landward on the shelf as well as some uplift from the Chittim Arch, this area did not reach the same level of hydrocarbon maturity as La Salle County. Therefore, it produces a much more condensate-rich gas and potentially volatile oil in the shallowest areas. To the northeast, in Live Oak, Karnes and DeWitt Counties (among others), the Eagle Ford is being explored primarily along the backside of the Edwards Reef. These areas generally produce condensate and gas.

More production data and exploration are required to determine the full extent of the Eagle Ford formation, but the results are promising and highlight the reason the Eagle Ford has become one of the most prolific unconventional plays discovered to date.

Stimulated Reservoir Volume

In unconventional reservoirs, geomechanical conditions may allow the creation of discrete fracture networks that can be initiated and propagated in multiple planes, as seen in microseismic mapping. The dominant or primary fractures propagate in the x-z plane perpendicular to the minimum horizontal stress. Discrete fractures created in the x-z and y-z planes are vertical, while the induced fractures created in the x-y plane are horizontal. Microseismic data collected during a fracture treatment can be used to calibrate the fracture model by inferring the fracture network aerial extent, fracture height and half-length, and fracture plane orientation. Effective hydraulic fracture treatments in shale plays create large stimulated reservoir volumes (SRVs) that provide a propped connective path to the horizontal well bore.

By solving for global, first-order parameters (continuity, mass and momentum conservation, and width opening), discrete fracture networks can be modeled using a fracture simulator. Fracture treatment pressure matches were performed on both the A and B wells using a commercially available DFN simulator (elliptically gridded) for predicting fracture propagation and extent in fractured and naturally fractured reservoirs. The simulation results for both wells evaluated the interrelationships between fracture geometry and aerial extent based on flow regimes, wall roughness and proppant transport and settling options.

The hydraulic fracture simulations also account for extended well bore storage and pressure loss caused by a horizontal fracture that initiates through the extended near-well bore region and then reorients as it grows away from the well bore into the vertical plane. This extended well bore phenomenon can create substantial net pressures and stress gradients of 1.0 psi/foot or greater. This pressure also is dependent on the mechanical properties of the formation rock encountered at the fracture initiation points.

Unfortunately, at times, some unconventional reservoirs are labeled with fracture gradients greater than 1.0 psi/foot and then inaccurately assumed to exhibit created hydraulic fractures in the horizontal plane. In reality, fracture gradients greater than 1.0 psi/foot are a result of shale storage and extended well bore effects, and not a physical characteristic of the fracture extension pressure. This is not to say that the fractures in the network do not have a horizontal component, but it is not likely to be the dominant characteristic. There may be horizontal components in the near-well bore region, but there has been enough microseismic data and positive production responses to indicate that the far-field fractures are vertical.

The network grid spacing is assumed to be approximately proportional to the zone thickness as a first-order approach. The refinement of this is to consider the net effective pay (NEP) and then the leak-off height over that thickness. In the simulations for wells A and B, a value of 75 feet was used for fracture spacing in both the minor and major axes directions. Horizontal fractures were not modeled discretely in the simulator, but were accounted for in the extended well bore pressure loss/shale storage function.

The proppant settling velocity selected for these simulations was a modest 0.10 feet/minute with uniform proppant distribution throughout the entire created fracture network. These options are suggested because fractures do not behave as smooth-walled, planar features. Instead, they have roughness, pinch points and oth-

FIGURE 1A

Well A Production Logging Results Showing Cumulative Gas Flow and Water Production

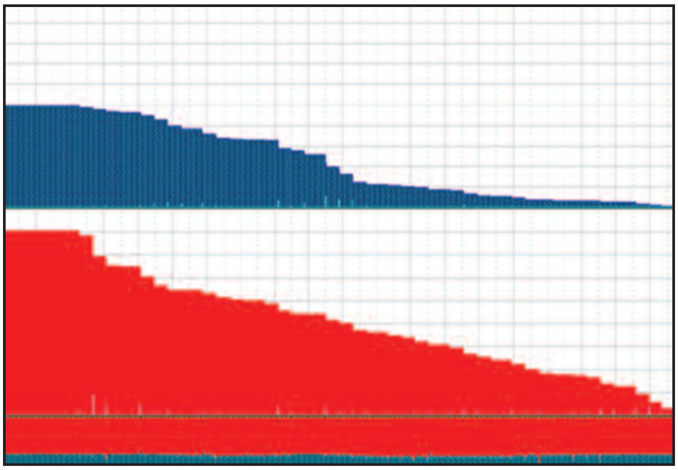
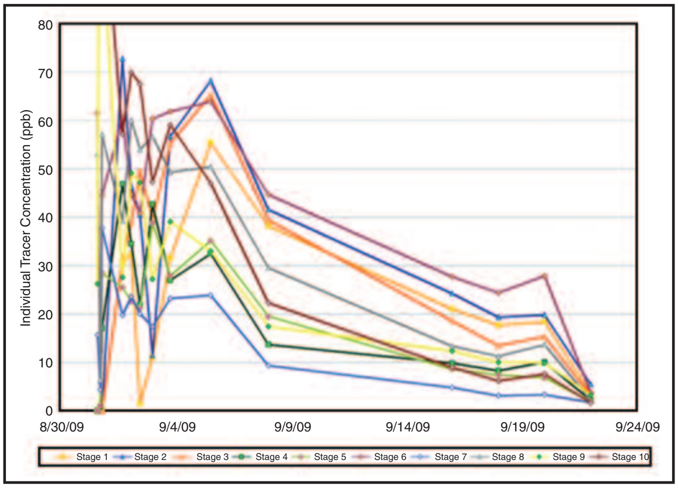


FIGURE 1B

Chemical Concentration by Stage for Well A



er unconformities that do not allow all the proppant transported by slick water treatments to settle to the bottom of the fracture.

Fracture treatment pressure was matched assuming that the fracture growth from the four clusters in each stage would interact and propagate within the same overall fracture network. It was assumed that there would be no dominant cluster in the interval, with one large fracture network created along the perforated interval length.

An analytical solution methodology for predicting the flow behavior of multiple transverse finite-conductivity vertical fractures intercepting horizontal well bores was utilized for the production history match on both wells. The numerical solution is applicable for finite-conductivity vertical fractures in rectangular-shaped reservoirs. The solution accounts for the high initial production from multiple transverse fractures and matches the late-time production decline as a result of fracture interference. The effect of choked skin also was examined.

This engineering methodology provides a simple way to predict the production behavior of multiple transverse fractures, accounting for production interference and spacing along the horizontal well bore. The results were used to understand the effective fracture stage size and cluster spacing.

Dry Gas Well

The horizontal Eagle Ford Well A was completed with a 10-stage fracture stimulation treatment using slick water, linear gel and 40/80-mesh lightweight ceramic proppant in a 4,000-foot lateral. Composite flow-through bridge plugs provided stage isolation. Each 400-foot stage was perforated with four, two-foot clusters spaced every 75 feet (40 clusters total). In each stage, the first and last perforation intervals were shot at six shots per foot, and the middle two intervals were shot at 12 twelve shots per foot. The average treating rate and surface treating pressure were approximately 50 barrels/minute and 8,900 psi, respectively.

Proppant concentration was increased during the stage from 0.25 to 1.5 pounds/gallon without using slick water sweeps. Linear gel was used as the carrier fluid in the later stages at concentrations of 0.75-1.5 pounds/gallon. The average proppant volume placed per stage was 250,000 pounds with 11,300 barrels of water per stage.

A petrophysical analysis was conducted on Well A to evaluate reservoir characteristics and potential, characterizing the effective porosity, permeability, mineralogy and organic content, and providing net estimates to illustrate the variability of the formation. Traditionally, net effective pay determination is based on some predetermined cutoff for water saturation, clay volume, permeability, resistivity, porosity, etc. Defining the NEP interval in shale formations is not a straightforward process. The pay zone height determined for Well A was 283 feet, and reservoir pressure was estimated using a pore gradient of 0.76 psi/foot. Mechanical rock properties were log-derived from an acoustic log run in the vertical section, defining values for stress, Young's modulus, Poisson's ratio and fracture toughness.

Following the 10-stage treatment, Well A was flowed backed and the isolation plugs were drilled out with coiled tubing. As shown in Figure 1A, a production log was run to determine flow contribution from each stage (and clusters). The results showed a total gas flow rate of 4.015 million cubic feet a day, a water rate of 99 barrels a day, and that all fracture stages were contributing to production. Stage 8 calculated as the minimum gas contribution of 5 percent and stage 10 calculated as the maximum flow rate of 19 percent. Results from the chemical tracers present in the flow back samples collected during the three weeks of initial flow back operations also showed contribution from all 10 stages, although not in equal percentages (Figure 1B).

Another benefit of running production logs and radioactive tracers is to identify if an individual cluster took fluid/proppant and is producing. On average, only two of the four clusters per stage appeared to have been effectively stimulated and producing appreciable amounts of gas. Similar results showing approximately half (or less) of the perforated clusters contributing to production have been noted in Marcellus wells. Radioactive tracers along the horizontal well bore suggested that 28 of the 40 clusters took radioactive material, and the production log indicated that only 27 clusters were contributing gas (2 percent volume or greater) in Well A.

The pressure match illustrated here is for Stage 9. The fracture network simulated for Well A is based on discrete fracture spacing of 75 feet in the major and minor axes. The DFN aspect ratio (width-to-length) was assumed to be about 0.30. This assumes that there is limited growth of secondary fractures away from the axis of the primary fracture. The surface and calculated bottom-hole pressure match is shown in Figure 2A. The dominant fracture characteristics (height, width and length) are shown in Figure 2B. Created fracture length is 776 feet and total fracture height is 358 feet and maximum width at the perforations is 0.22 inches. The extended well bore effect match indicates an average 500 psi pressure loss, which dissipated within two minutes after shut in.

Average pay zone conductivity was 20-80 mD throughout the pay section. The concentration per area profile suggested a loss of concentration at the well bore because of overflushing during the fracture treatment while setting plugs. Net pressure and fracture fluid efficiency at the end of pumping was 206 psi and 84.4

FIGURE 2A

Pressure History Match for Well A (Connected-Cluster DFN)

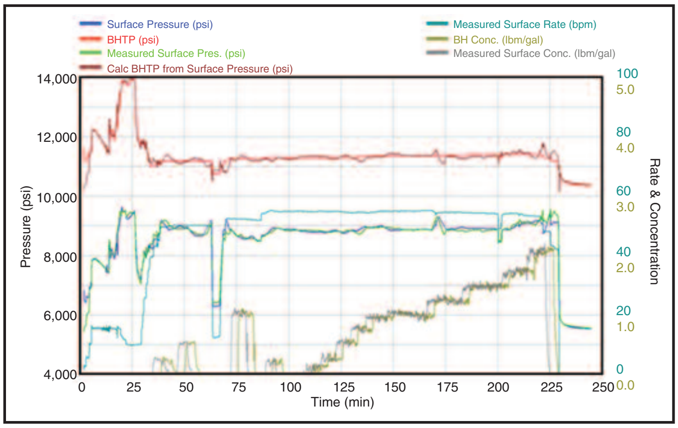
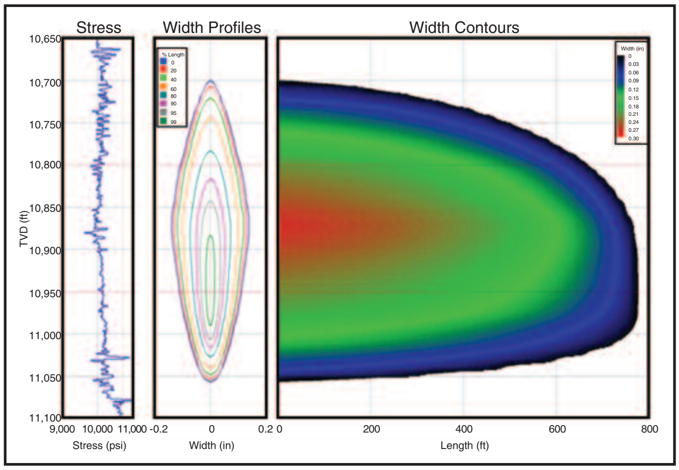


FIGURE 2B

Stress, Width Contours and Length for Well A (776-foot Fracture Half-Length)



percent, respectively. Figure 3A illustrates the aerial view of the DFN for connected clusters. Total created DFN length is 1,552 feet (776 feet created half-length) along the major axis and 450 feet along the minor axis, resulting in a stimulated reservoir volume of 169 million cubic feet (Figure 3B).

Production History Match

Figure 4A shows the daily rate and cumulative production for Well A for nine months. The nine-month production history match along with the calculated bottom-hole flowing pressure (BHFP) is shown in Figure 4B.

The concept of fracture conductivity often is overlooked as an important stimulation design variable in shale plays. However, well orientation and fracture conductivity are the two fundamental parameters that must be carefully evaluated when designing horizontal wells. When transverse fractures are created along a horizontal well bore, the resulting radial flow converges at the well bore and results in tremendously high hydrocarbon velocities in the near-well bore fracture and perforation tunnels. In this orientation and at these velocities, the near-well bore conductivity is typically inadequate and becomes a restriction to flow. This effect can be quantified by defining a horizontal choked skin (HCS).

The history match for Well A was based on two scenarios for HCS skin:

- The tail-in of higher-conductivity proppant, because the conductivity near the well bore should be greater than average fracture conductivity throughout the fracture network, and;
- No proppant tail-in, since fracture treatments may be overflushed and not benefit from the higher fracture conductivity near the well bore.

All cases assumed uniform fracture conductivity and equally spaced and sized fractures. To better define the effective fracture length, system permeability and fracture conductivity, the history match solution also was run with a minimum number of fractures (10, or one fracture per stage), an average number of fractures (20, or two per stage) and a maximum (40, or four per stage). This provides a range of solutions depending on the number of transverse fractures contributing to the well bore.

Since there were no unique history match solutions, it is helpful to choose a solution that converges with other data sets. Given the results of the production and radioactive tracer logs, it is reasonable to use the 20 transverse fracture analyses, since approximately half of the 40 perforated clusters appear to be driving production. The fracture treatments were overdisplaced so the 20 transverse fracture case with no proppant tail-in resulted in a propped fracture length of 250 feet, fracture conductivity of 2.0 mD/foot, a choked skin of 0.0150, and a formation permeability of 16.8 nD. Overflushing (no proppant tail-in) in the 20 fractures would reduce the calculated fracture half-length by 10 percent.

Although there is less than one year of production data, the history match results for 20 transverse fractures seem reasonable.

FIGURE 3A

DFN Length (1,556 feet) And Width (450 feet) for Well A

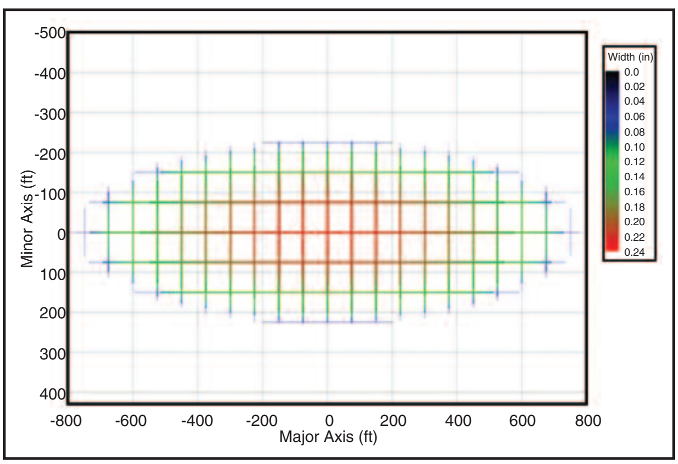


FIGURE 3B

Well A Stimulated Reservoir Volume (169 million cubic feet)

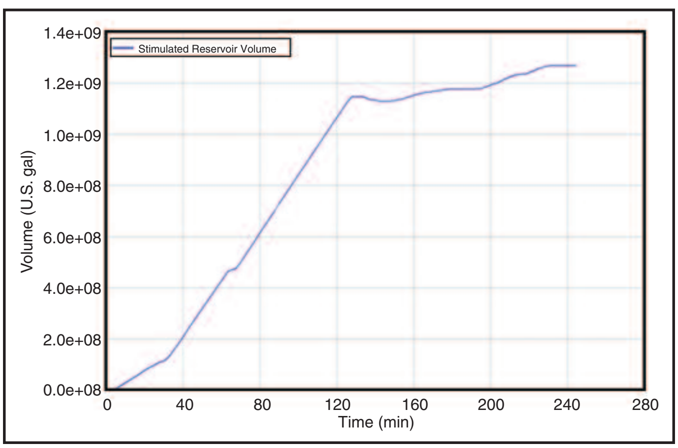


FIGURE 4A

Well A Rate and Cumulative Production (250 days)

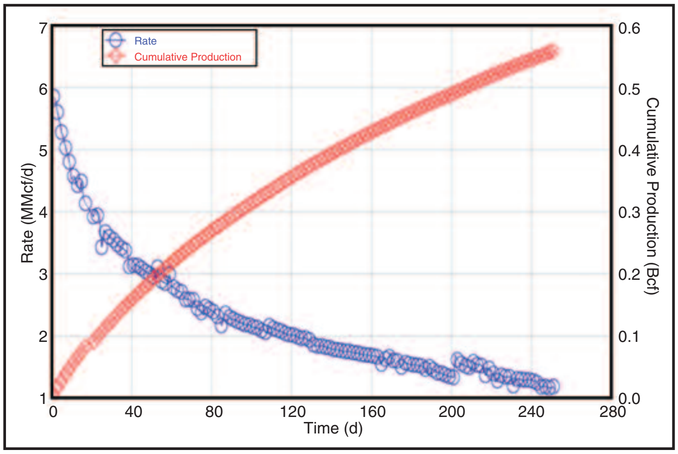
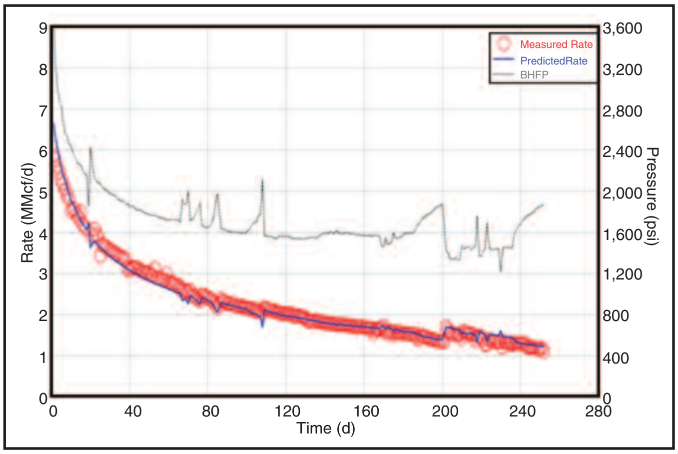


FIGURE 4B

Well A History Match of Measured And Predicted Flow Rates with BHFP For Multiple Transverse Fractures



The results then were used to forecast the production rate and cumulative production for 10 years using a bottom-hole flowing pressure of 1,200 psi. The cumulative production after one and five years is 0.7 billion and 1.8 billion cubic feet, respectively. It must be noted that these longer-term projections should only be used for comparing fracture design parameters, and not for reserve or EUR calculations. Long-term production and BHFP data are necessary for more accurate projections.

Condensate Well

A similar methodology was used to match the horizontal Eagle Ford Well B. The well was completed with a 12-stage proppant fracture stimulation using slick water and ceramic proppant in a 4,000-foot lateral. Composite flow-through bridge plugs were again used for stage isolation. Each stage was perforated with four, two-foot clusters (48 total) spaced 75 feet apart. Eight additional clusters were shot in Well B within the same lateral length as Well A, because the distance from the plug to the perforated cluster was reduced. All perforation intervals were six shots per foot.

The average treating rate and surface treating pressure were 70 bbl/minute and 8,500 psi, respectively. Proppant concentration was increased from 0.25 to 1.5 pounds/gallon using slick water sweeps between the proppant-laden stages for each stage. The average proppant volume placed per stage was ~270,000 pounds with 12,500 barrels of water per stage.

A petrophysical analysis also was conducted on Well B to evaluate reservoir characteristics and potential to characterize the effective porosity, permeability, mineralogy and organic content and estimate net pay. The pay zone height determined for Well B is 224 feet. Reservoir pressure was estimated using a pore gradient of 0.65 psi/foot. Mechanical rock properties were determined from an acoustic log run in the vertical section, with log-defined values for stress, Young's modulus, Poisson's ratio and fracture toughness.

A post-fracture production log (Figure 5A) was run after drilling out all the plugs to determine flow contribution from each stage. The results showed a total gas flow rate of 4.184 MMcf/d and a water rate of 89 bbl/d, with all stages contributing to production. Stage 8 showed the minimum gas contribution of 3 percent and stages 4 and 1 showed the maximum flow rate of 14 percent. Results from the chemical tracers present in the flow-back samples collected during the three weeks of initial flow back operations also showed contribution from all 12 stages (Figure 5B).

The analysis revealed that 29 of the 48 clusters took radioactive material, and that 21 of the clusters were contributing gas on the production log. Again on average, only two of the four clusters appear to have been effectively stimulated and producing appreciable amounts of gas.

The pressure match illustrated here is for Stage 4. The fracture network simulated for Well B is based on discrete fracture spacing of 75 feet in the major and minor axes. The DFN aspect

FIGURE 5A

Well B Production Logging Results Showing Cumulative Gas Flow and Water Production

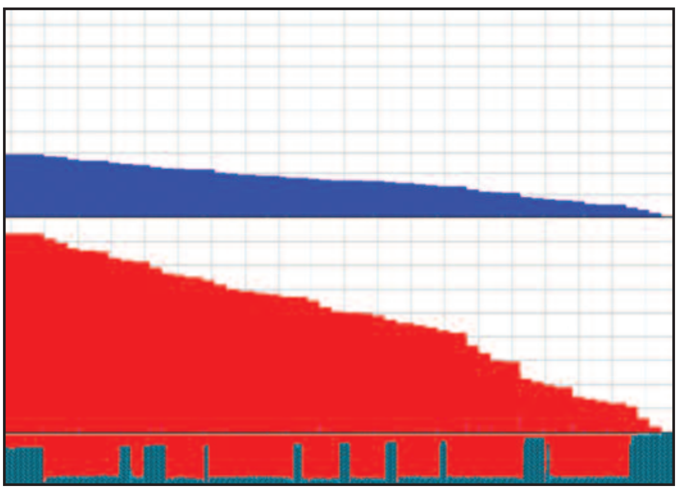


FIGURE 5B

Chemical Concentration by Stage for Well B

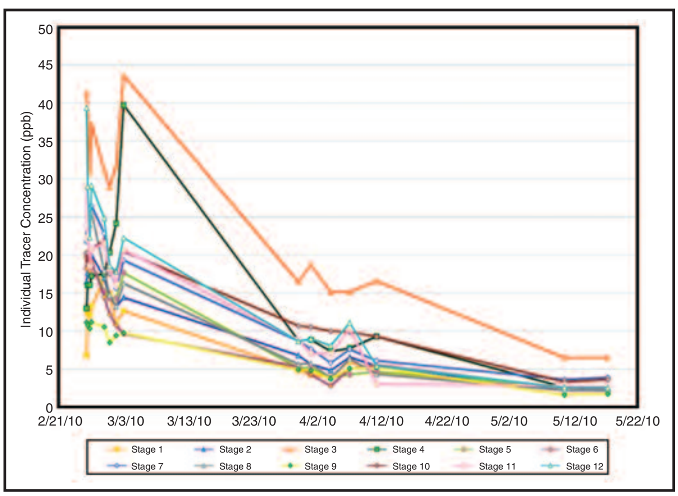


FIGURE 6A

Pressure History Match for Well B (Connected-Cluster DFN)

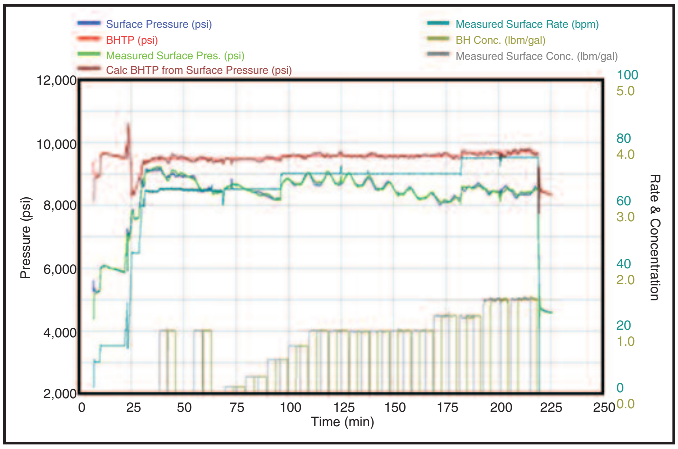
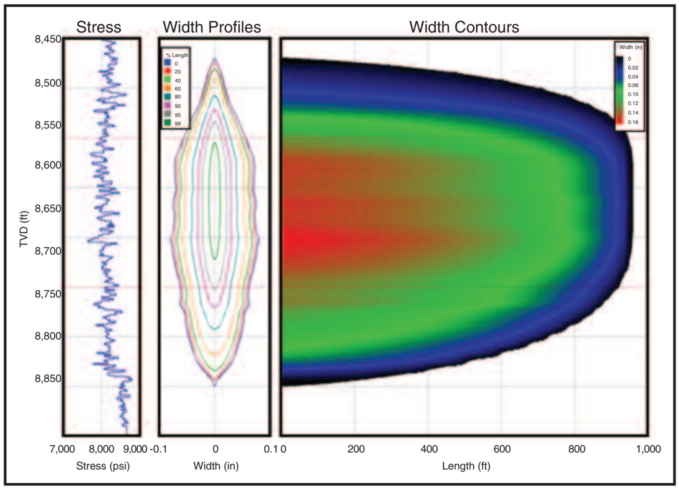


FIGURE 6B

Stress, Width Contours and Length for Well B (960-foot Fracture Half-Length)



ratio was assumed to be 0.40 (calibrated from microseismic). The surface and calculated bottom-hole pressure match is shown in Figure 6A, with the dominate fracture characteristics (height, width and length) shown in Figure 6B. Created fracture length is 960 feet with a total fracture height of 331 feet and a maximum width at the perforations of 0.14 inches. The extended well bore effect match indicates 250 psi pressure loss, which dissipated within three minutes after shut in. The average pay zone conductivity was approximately 40 mD throughout the pay section.

An apparent loss of concentration at the well bore is attributed to overflushing during the fracture treatment. Net pressure and fracture fluid efficiency at the end of pumping was 232 psi and 67.3 percent, respectively. Figure 7A shows the aerial view of the DFN for connected clusters. Total created DFN length is 1,920 feet (960 feet created half-length) along the major axis and 700 feet along the minor axis. The stimulated reservoir volume is 321 million cubic feet (Figure 7B).

Microseismic Mapping

Microseismic mapping was used to detect and locate microseismic events in Well B's 12 frac stages, with monitoring conducted in a nearby offset well. The technology was utilized to provide estimates of fracture height, length and azimuth during the stimulation stages. The majority of microseismic activity was observed during the first part of each fracture stage. Overall, the fracture azimuths for all the stages ranged from north 45 degrees east to north 55 degrees east, with a principal fracture azimuth of north 50 degrees east, which is basically transverse to the Well B lateral. Fracture containment within the Eagle Ford groups was achieved, with most of the microseismic activity focused in the upper pay zone. The average fracture height was 260 feet, with some upward growth into the Austin Chalk and downward growth into Buda group observed during the stimulation treatments.

Fracture network half-lengths ranged from 450 to 900 feet (averaging 700 feet). Fracture network widths ranged from 265 to 730 feet, with stage overlap imaged in some instances, indicating fracture complexity. Figure 8A illustrates the map view for all 12 stages of Well B. The side view for all stages in Well B is shown in Figure 8B. Specific to Stage 4, the fracture network width was observed to be 600 feet and half-length was observed to be 700 feet, with the fracture height observed to be 310 feet.

Figure 9A shows the daily rate and cumulative production for Well B for 120 days. Petrophysical analysis of the reservoir indicated 224 feet of net pay in the Upper and Lower Eagle Ford intervals. The microseismic data and the fracture geometry predicted by the DFN modeling indicated that the entire interval was contacted by the fracture treatments. The production history match over 120 days along with BHFP is shown in Figure 9B. Well B produces 200 bbl/d of condensate, so the production rates used in the history match are total gas rate, including equivalents. Note that there was a shut-in period of 16 days by field operations during the production period.

The history match also was based on the tail-in of higher-con-

FIGURE 7A

DFN Length (1,920 feet) And Width (700 feet) for Well B

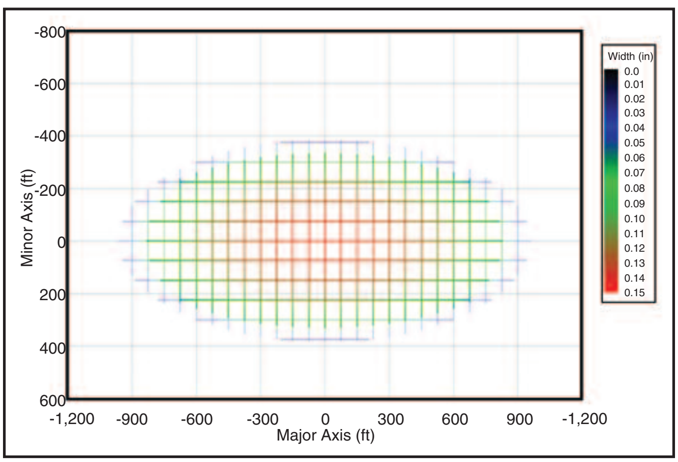


FIGURE 7B

Well B Stimulated Reservoir Volume (321 million cubic feet)

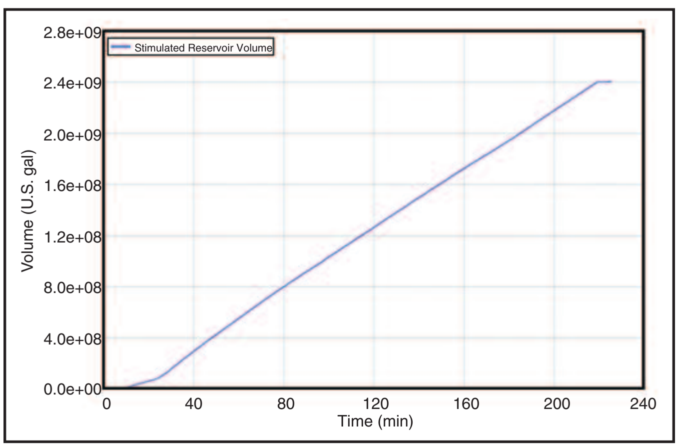


FIGURE 8A

Microseismic Mapping Results For all 12 Stages in Well B (Map View)

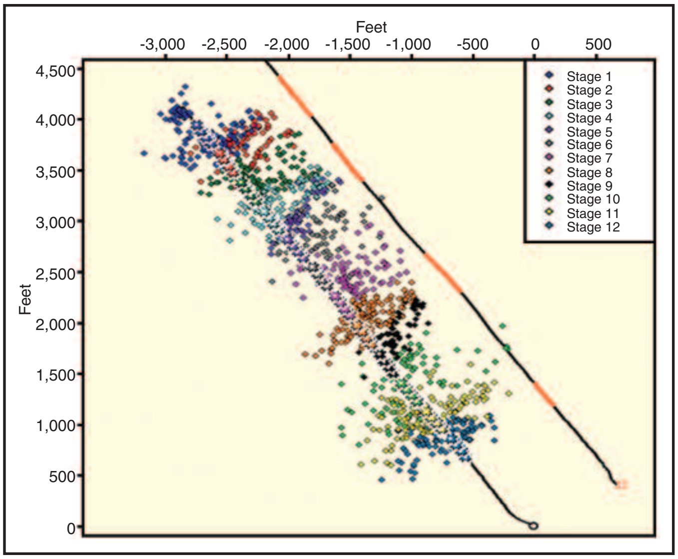
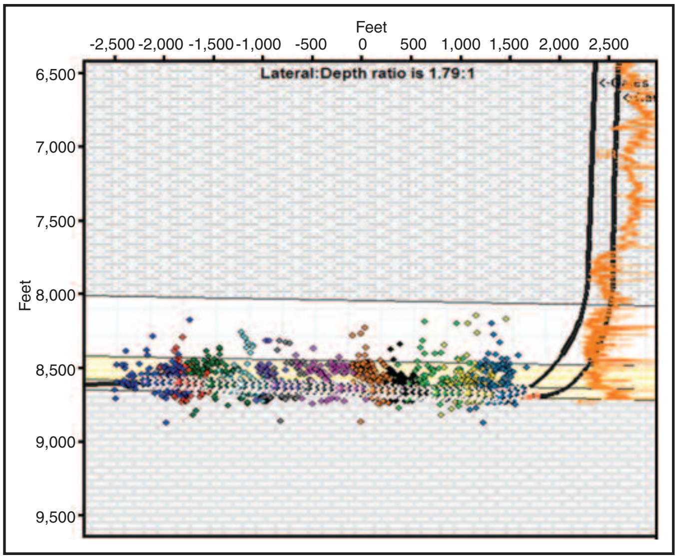


FIGURE 8B

Microseismic Mapping Results For all 12 stages in Well B (Side View)



ductivity proppant, because the conductivity near the well bore should be greater than the average fracture conductivity throughout the fracture network. Also, a case with no proppant tail-in was run since the fracture treatments were overflushed and may not benefit from higher near-well bore conductivity. All cases assumed uniform fracture conductivity and equally spaced and sized fractures. To better define the effective fracture length, system permeability and fracture conductivity, the history match solution was again run with the one, two and four fractures per stage.

The production log for Well B suggested that 21 transverse fractures were contributing to production and the radioactive material log illustrated that 29 fractures were stimulated. Again, it is reasonable to use half of the fractures (24 transverse fractures case) for the analyses and forecast.

The fracture treatments were overdisplaced, so the 24 transverse fracture case (with no proppant tail-in) was used for production forecasting. Overflushing (no proppant tail-in) reduces the fracture half-length by 18 percent. The history match results for 24 transverse fractures seem reasonable, but long-term production and BHFP data will allow more accurate flow predictions. Production rates and cumulative production were forecast for 10 years using a decreasing BHFP from 2,000-1,500 psi. The cumulative production after one and five years is 1.3 billion and 4.7 billion cubic feet, respectively.

Overview Of Results

A number of completion technologies and engineering methods were used in wells A and B to better understand the completion and production results for Eagle Ford Shale wells. The results from microseismic analysis, production logging and tracer technology (radioactive and chemical) were used to support the results for the fracture modeling and production history match simulations.

The DFN simulation results provide the full extent of the predicted complex geometry along the major and minor axes. Well B's DFN simulation results calculate the fracture network with a created half-length of 960 feet and a total width along the minor axis of 700 feet using an aspect ratio of 0.4 as model input. Microseismic results provided a created half-length of 700 feet with a 600-foot wide fracture network. This is very good agreement between the two technologies. The microseismic network results are 80 percent of the created fracture network. The created geometry from the DFN is the absolute extent of the network

FIGURE 9A

Well B Rate and Cumulative Production (120 days)

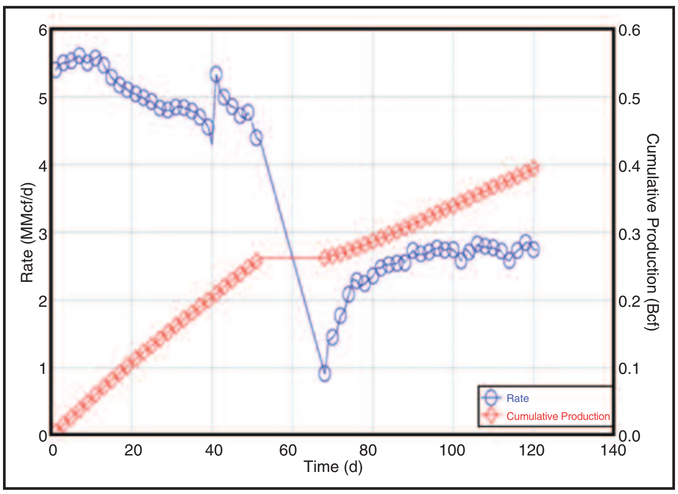
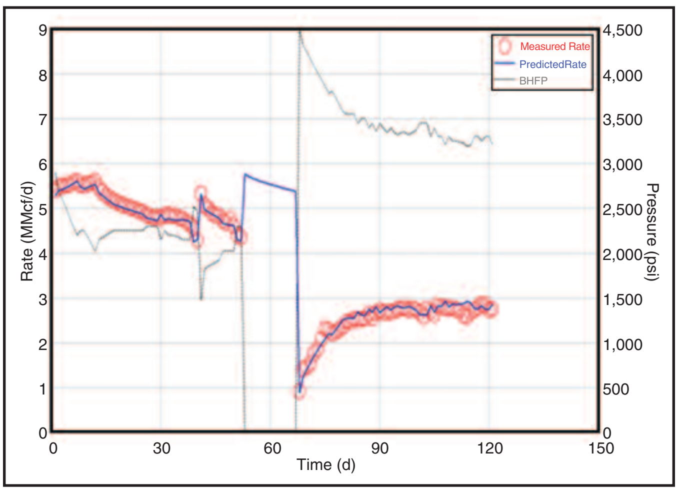


FIGURE 9B

Well B History Match of Measured And Predicted Flow Rates with BHFP For Multiple Transverse Fractures



and the edges do not have the width to accept proppant.

The fracture modeling and production history match results can be used to define a minimum proppant concentration for future fracture designs in the field. The production logging and tracer technologies helped determine the number of contributing fractures that were used in the production history matching simulations. The history match for Well A solved for an effective fracture length of 250 feet. This corresponds to a minimum proppant concentration per area between 0.15 and 0.2 pounds per square foot. The propped fracture length of 330 feet is obtained in the production history match for Well B in which sweeps were used. This corresponds to a minimum proppant concentration per area of 0.15 pounds per square foot. With this parameter defined, it is possible to run sensitivities on fluid volume, proppant type and scheduling to affect the created fracture network.

The fracture treatment pressure match results indicate a stimulated reservoir volume of 169 million cubic feet for Well A and 321 million cubic feet for Well B. Well A did not have excessive sweep stages within the fracture treatment and Well B had a sweep after every proppant stage. Well B sweep stages accounted for 10 percent more fluid volume than in Well A. Since the volume pumped in Well A is 90 percent of Well B, the higher stress and greater vertical depth in Well A probably contributed to the smaller stimulated reservoir volume.

However, the larger stimulated reservoir volume in Well B (almost twice that of Well A) probably does not result in greater gas volume being recovered in the Eagle Ford as in other shale plays. The greater production from Well B is not because sweeps were used during the stimulation treatment. The production difference between the two wells is because Well B has a reservoir flow capacity six times greater than Well A, and not because of a greater SRV.

Optimizing Conductivity

Production simulations for 40/80 lightweight ceramic, 40/70 resin-coated sand and 40/70 uncoated sand were conducted to assess the conductivity of each proppant type under Eagle Ford flowing well conditions. The results confirm a benefit with improved conductivity. Using the history match conductivity of 2.02 mD-foot for the lightweight ceramic, the resin-coated sand conductivity was calculated to be 0.66 mD-foot and the sand conductivity, 0.16 mD-foot. Well A simulated production rates at three years for ceramic, resin-coated sand and sand proppants are 0.72 MMcf/d, 0.68 MMcf/d and 0.49 MMcf/d, respectively. Cumulative production after three years was predicted to be 1.38 Bcf for the lightweight ceramic, 1.16 Bcf for the resin-coated sand and 0.65 Bcf for uncoated sand.

However, conductivity changes also should affect the effective fracture half-length. Therefore, a sensitivity case was run in which the effective fracture half-length was decreased along with conductivity. The flowing lengths for resin-coated sand and natural sand were set at 175 feet and 113 feet, respectively, assuming the effective fracture half of the lightweight ceramic proppant was the full matched 250 feet. As expected, when both conductivity and fracture half-length were changed, production rates at three years for resin-coated sand and sand further decreased to 0.51 MMcf/d and 0.31 MMcf/d, respectively. The cumulative production for Well A after three years for the resin-coated proppant is 0.90 Bcf and 0.46 Bcf for natural sand, equating to 35 and 67 percent less production after three years, respectively, than ceramic proppant.

Applying the same methodology to Well B, resin-coated sand conductivity was reduced to 0.49 mD-foot and sand conductivity to 0.12 mD-foot. Well B production rate at three years for ceramic, resin-coated sand and sand proppants are 2.24 MMcf/d, 1.46 MMcf/d and 0.56 MMcf/d, respectively. The cumulative production after three years was predicted to be 3.24 Bcf for the ceramic proppant, 1.79 Bcf for the resin-coated sand and 0.61 Bcf for natural sand.

After reducing the effective fracture half length, the flowing lengths for resin-coated sand and natural sand were reduced to 231 and 149 feet, respectively. After changing both conductivity and fracture half lengths, the production rates at three years was 1.30 MMcf/d for resin-coated sand and 0.53 MMcf/d for uncoated sand. Cumulative production after three years for resin-coated sand is 1.66 Bcf and 0.62 Bcf for natural sand, or 49 percent and 81 percent less production after three years, respectively, than ceramic proppant. ❐

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