Optimizing Frac Packs

Fracturing for sand control has evolved as applications expand to deeper, more demanding reservoirs. A reliable test to establish fracture-closure pressure along with improved fluid-selection criteria has helped engineers reduce completion damage in ultradeepwater wells. These field-proven techniques can also be applied in other areas to ensure successful tip-screenout treatments and placement of highly conductive proppant packs.

^Frac packing. Tip-screenout (TSO) designs use fluids that leak off early in a treatment, causing proppant to pack off at the fracture tips (top). Pumping additional proppant-laden fluid, or slurry, causes the biwing fractures to inflate as proppant packs back toward the well (middle). A TSO generates enough displacement in soft formations to create an annular opening around the wellbore that fills with proppant. This external pack prevents sand production from nonaligned perforations and further reduces near-well pressure drop (bottom).

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As offshore oil and gas development moves into harsher, more demanding deepwater environments, frac-packing utilization and methods continue to expand and evolve based on specific field experience and requirements. These tip-screenout (TSO) fracturing treatments performed in conjunction with gravel packing of mechanical screens now represent almost 65% of sand-control completions in the Gulf of Mexico, USA. Since it was first applied in the early 1990s, frac packing has become one of the most widely used methods for completing wells in weakly consolidated formations.

This combined stimulation and sand-control technique has proved effective in a wide range of formations with mobile solids, especially high-permeability reservoirs. Frac packs consistently yield sustained production increases compared with viscous slurry packs or high-rate water packs.

Frac packing avoids many of the productivity impairments common in conventional cased-hole gravel packs by effectively bypassing formation damage, or skin, and by creating an “external” pack to stabilize perforations that are not aligned with the propped fracture (previous page).

A TSO design limits hydraulic fracture extension, or length, by using less-efficient stimulation fluids with high leakoff rates that cause the proppant-laden slurry stages to dehydrate early in a treatment. Proppants pack off near the end, or tip, of dynamic fractures, causing them to inflate like a balloon as additional slurry is injected. Proppant then packs back toward the well, which promotes grain-to-grain contact and generates a wider, more conductive pathway after the dynamic fracture closes.

In many ways, frac packing is a mature technology. Service companies have comparable pumping equipment, stimulation vessels, downhole tools and laboratory support. They also provide similar fluids, proppants, treatment additives and damage-removal techniques. Other well technologies—intelligent well completions, multiple-zone production monitoring and control, real-time data and information transfer, safety and quality control—have also reached a relatively high level of maturity.

The average completion skin for frac packs is typically less than the skin for other sand-control methods, but there is room for improvement. Frac-pack productivity may be lower than expected because of a combination of factors, including perforation damage, failure to achieve TSO, incomplete fracture or proppant-pack coverage and high pressure drops through downhole sand-exclusion screens and well-completion equipment.

Frac-pack optimization involves addressing all of these completion-design factors to reduce overall skin and improve well productivity, to maximize hydrocarbon recovery, and to help operators avoid future well interventions. The latter objective is critically important in deepwater fields, particularly those with subsea wells, where remedial operations to remove damage or restimulate wells are extremely difficult, complex and costly.

Total, Marathon and Schlumberger refined existing completion practices and frac-packing techniques in the Gulf of Mexico using field experience and improved computer modeling of fracturing and frac-packing processes. Completion engineers now select optimal treatment fluids and adjust frac-pack designs to account for in-situ temperatures and fluid shear during treatment execution.

This article discusses methods for cleaning perforations and for selecting treatment fluids that achieve effective TSO fractures, including a reliable means of determining fracture-closure pressure. It presents well-completion equipment that ensures complete stimulation and gravel packing across long intervals, maximizes internal flow area, and allows evaluation of frac-packing efficiency. It also summarizes field experience and results from the ultradeepwater Aconcagua and Camden Hills fields in the Gulf of Mexico Canyon Express project, which contributed to a better understanding of frac packing.

Effective Perforations

Reservoir stimulation, or fracture conductivity, alone does not ensure an optimal frac pack. An effective external proppant pack is also required. A ring of proppant around the wellbore stabilizes all the perforations and hydraulically connects them with the propped fracture. This further minimizes frac-pack skin and reduces pressure drop across the completion interval to help avoid formation failures and subsequent sand production. An external pack is also the basis for screenless completions that control sand without mechanical screens and internal gravel packs.

Computer modeling indicates that unaligned perforations, those oriented away from the preferred fracture plane (PPF), contribute as much as 50% of the inflow from high-permeability formations (above). This underscores the importance of eliminating flow restrictions in and around all of the perforations.
Explosive-jet perforating causes a crushed zone of damage around perforation tunnels. This damage can be addressed by pumping acid to remove perforating damage and debris prior to frac packing or by applying more effective perforating practices, such as dynamic underbalance techniques. Analysis of Gulf of Mexico well completions indicates that skin factors were high when acid volumes of less than 20 gal/ft \([0.24 \text{ m}^3/\text{m}]\) were used across perforated intervals; pumping acid volumes of 40 to 50 gal/ft \([0.5 \text{ to } 0.6 \text{ m}^3/\text{m}]\) with effective diversion across the entire zone minimized completion skin (above left).

Careful consideration should also be given to selecting perforated intervals to avoid unwanted hydraulic fracture-height growth in shale layers above and below productive intervals. Fracturing into shale restricts fluid leakoff. Dynamic fractures in shale remain open longer because treating fluids do not leak off fast enough. This also makes it difficult to obtain a complete gravel pack around the top of sand-control screens. Reducing perforation intervals by 3 to 5 ft \([0.9 \text{ to } 1.5 \text{ m}]\) near shale interfaces to allow continued fluid leakoff from dynamic fractures is recommended (above right).

After perforating, a successful TSO treatment is essential to generate wide fractures and external proppant packs, and to promote grain-to-grain interactions within the proppant pack. Improved frac-pack productivity. Production from frac-packed wells in the Gulf of Mexico Matagorda Island area doubled after switching from a fluid system with a 50-pounds per thousand (ppt) gallon polymer concentration in Wells 1 to 4 (red) to an optimized 35-ppt polymer fluid in Wells 5 to 7 (blue). The productivity ratio in Well 7 would have been higher, but output was limited by small production tubing.
proppant contact from fracture tip to wellbore. Achieving these interrelated objectives requires selection of appropriate treatment fluids based on specific frac-packing criteria and analysis of engineered injectivity-calibration tests.

**Fluid Selection**

Treatment-fluid properties play an influential role in generating hydraulic fracture geometry and effectively placing proppant during any fracturing treatment, but are particularly important during frac packing. Dynamic fracture width, length, height and proppant-transport capability are determined primarily by fluid volume, viscosity and leakoff coefficient. Optimal treatment-fluid characteristics are also important for minimizing completion damage during posttreatment flowback and cleanup.

Initially, fluid-selection criteria for frac packing were based on conventional fracturing treatments in low-permeability, consolidated reservoirs where fracture widths are narrow—high fluid-shear rates—and fluid leakoff is low—less formation cool down. This led to the use of frac-packing fluids with high polymer concentrations and higher efficiencies, or lower leakoff rates, even in formations with higher permeabilities.

However, completion engineers soon found that less-efficient frac-packing fluids with lower polymer loadings and higher leakoff rates tend to cause less formation and proppant-pack damage, resulting in better well productivities (previous page, bottom). Failing to consider temperature changes and variations in shear rate also resulted in unnecessarily high polymer loadings, which decreased the chance of achieving a tip screenout. Therefore, designers began basing fluid selection and polymer loadings on actual in-situ temperatures.

Downhole temperatures decrease significantly during pretreatment injectivity and calibration tests and actual frac packing because of rapid fluid leakoff into highly permeable formations (top right). This cool down subsequently increases apparent treatment-fluid viscosity inside the dynamic fracture and decreases leakoff into the formation.

In addition to changes in fluid properties caused by temperature effects, treatment fluids experience varying shear rates as fractures extend, or propagate. Fluid velocities and shear are high during fracture initiation, but decrease by several orders of magnitude after TSO, causing corresponding increases in apparent viscosity (right).

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The viscosity of gelled polymer fluids must break down completely after a treatment. Frac-packing fluids that do not break quickly can leave polymer residue in propped fractures and proppant packs, which impairs initial well productivity. Chemical and breakers, such as oxidizers, encapsulated oxidizers and enzymes, added during various stages of a job, degrade borate-crosslinked fluids over time. The type of breaker and required concentration depend on polymer loading, temperature and pump time. The designed breaker loading for frac-packing treatments is determined by exposure time inside the dynamic fracture (right).

The initial stage, or pad fluid, which is pumped without proppant, leaks off faster because it is continuously creating and contacting new dynamic-fracture surfaces. After a tip screenout, fracture-propagation rate decreases, fluid efficiency increases, and the stages that follow the pad remain in the open fracture longer. Slurry stages pumped near the end of a treatment schedule have the least exposure time. When the first proppant-laden slurry stage reaches the perforations, pad-fluid viscosity should start degrading, and then quickly break down completely.

Intermediate slurry stages should remain stable for at least 30% of total pump time and then break. The final slurry stages should be stable for at least 20% of total pump time before breaking. The total time that pad and slurry stages remain stable should include workstring traveltime. A reliable value for minimum in-situ formation stress is critical in predicting fracture dimensions and designing these TSO treatments.

Fracture-Closure Pressure

Minifracture injectivity tests performed before a main treatment using the DataFRAC fracture data determination service verify parameters such as fracture-closure pressure, fluid leakoff coefficient and fluid efficiency. Reliable values for these parameters aid in calibration, optimization and final adjustment of treatment designs.

An incorrect fracture-closure pressure leads to an incorrect closure time and net pressure, and consequently, to a fluid efficiency, or leakoff coefficient, that is too low or too high. As a result, any adjustments to fluid and proppant schedules during the main treatment could result in failure to achieve a TSO and a less than optimal stimulation. A reliable fracture-closure pressure is also essential for generating accurate real-time net-pressure plots, which are used to predict fracture geometry and tip screenout.
To achieve a TSO that ensures a wider propped fracture, field engineers rely on net-pressure plots to make real-time decisions about continuing a treatment or ending the job early. Matching net-pressure behavior using a computer model also helps in estimating fracture dimensions and adjusting treatment designs.

Step-rate tests using ungelled fluids and DataFRAC analysis using the actual gelled treatment fluids involve pumping fluid into a formation to analyze pressure responses during and after injection (previous page, bottom). Pressure-decline analysis, the most commonly used method, incorporates standardized plots to identify the inflection point on a pressure-decline curve that represents fracture closure.

Under some conditions, however, the pressure response exhibits inflection points associated with mechanisms other than fracture closure—changes in flow regimes or gas influx—that sometimes lead to erroneous estimates. A more objective and reliable test was needed to correctly and consistently determine fracture-closure pressure and correctly characterize hydraulic fracture behavior.

Ideally, fracture closure should be activated by fluid flow and controlled primarily by the dynamic fracture opening and closing to provide a unique pressure response. Performed correctly, step-rate and flowback tests fit these criteria, as does the new equilibrium step-rate (ESR) test (above). The ESR test is similar to a conventional step-rate test with one exception.

This procedure decreases hydraulic fracture surfaces to an equilibrium area where injection rate equals leakoff rate to provide a more reliable indication of fracture-closure pressure. Fluid is injected at increasing rates to create a hydraulic fracture; then, rather than shutting in the well, the fluid-injection rate is reduced to the estimated fracture-propagation, or extension, rate and then held constant.

The volume and pressure in the dynamic fracture subsequently decrease until the fluid leakoff and injection rates reach equilibrium. At that point, fracture volume stops decreasing, and pressure stabilizes. Once this equilibrium pressure is reached, the well is shut-in and the fracture closes.

The ESR test provides a more reliable value for fracture-closure pressure, especially in high-permeability formations where treatment fluids leak off quickly and hydraulic fractures close quickly.

The closure pressure is unique and easy to identify, which avoids ambiguities associated with other methods. Fluid efficiency can also be estimated from the decline slope. A field-derived correlation for deepwater wells provides a reliable way to estimate in-situ stress.

In the past, a common misconception was that higher frac-pack productivities resulted from placing larger volumes of proppant in a formation. Skin data from frac-pack completions in the Gulf of Mexico plotted as a function of

proppant volume per foot indicate that increased proppant volumes do not necessarily decrease skin if the treatment failed to achieve a TSO (above). Another key aspect of ensuring effective TSO treatments is complete and effective fracture coverage and proppant placement across an entire productive interval.

Fracture Coverage and Proppant Placement
Frac-pack completion designs and downhole equipment must address the complexities of treating large reservoir sections and multiple completion intervals, some with perforated intervals longer than 150 ft [46 m] and with significant permeability and stress contrasts. Even carefully planned frac-packing treatments may end in failure if proppant packs off, or bridges, in the screen-casing annulus, restricting or blocking annular flow. Proppant bridging may cause early treatment termination, low fracture conductivity and incomplete gravel packing around screens.

Annular blockage near the top of a screen assembly prevents fracture stimulation and screen packing across deeper zones. Partial flow restriction in the annulus increases frictional pressure drop, restricts rate distribution and limits fracture-height growth across the completion interval, especially when fracturing zones with higher in-situ stresses. Annular voids below a proppant bridge increase the likelihood of subsequent screen failures caused by erosion from produced fluids and sand.

For homogeneous intervals that are less than 60 ft [18 m] thick, fracture height typically covers the entire zone. For longer intervals, the probability of complete fracture coverage decreases, and risk of proppant bridging increases. Long intervals may be treated in separate stages. This requires more downhole equipment, such as stacked frac-packing assemblies, and additional installation time, but these factors are often outweighed by increased treatment and completion effectiveness.

Alternate Path technology can also be applied to frac pack longer intervals (right). AllFRAC screens use hollow rectangular tubes, or shunts, welded on the outside of screens to provide additional flow paths for slurry. Exit ports with carbide-strengthened nozzles on the shunt tubes allow fluids and proppant to exit above and below annular restrictions, so that fracturing and annular packing can continue even after restrictions form in the screen-casing annulus.

Shunt tubes provide conduits for slurry to bypass collapsed hole and external zonal-isolation packers as well as annular proppant bridges at the top of intervals or adjacent to high-permeability zones with significant fluid leakoff. If annular restrictions form, injection pressure increases and slurry diverts into the shunt tubes, ensuring fracture coverage and proppant packing around screens across the entire completion interval.

Alternate Path technology also allows screen manufacturers to maximize internal screen diameters to reduce pressure drops through downhole assemblies and well-completion equipment. To accommodate higher injection rates, AllFRAC screens for frac packing have shunt tubes with slightly larger cross sections than the AllPAC screens used for gravel packing.

Effective treatment designs. Comparing Gulf of Mexico frac-pack completions indicates that placing higher volumes of proppant in the formation does not correlate with reduced skin factors. Three wells had extremely high skins, above 20 to more than 35, even though proppant volumes exceeded 2,000 lbm/ft [3,000 kg/m] of perforated interval. In these cases, high skins were attributed to not achieving a TSO.
When these frac-pack design considerations are carefully addressed, operators should expect desirable downhole and surface pressure signatures, indicating an effective TSO fracture and complete packing of the screen-casing annulus (above). Total and Marathon Oil Company successfully implemented optimized frac-packing techniques in two ultra-deepwater Gulf of Mexico gas fields.

**Deepwater Proving Ground**
Total E&P USA, Inc. operates the Aconcagua field 140 miles [225 km] southeast of New Orleans in Mississippi Canyon Block 305. The Camden Hills field operated by Marathon Oil Company lies in adjacent Mississippi Canyon Block 348. These two fields, along with the BP-operated King's Peak field, comprise the Canyon Express development (right).[^6]

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The four wells in the Aconcagua field, two wells in the Camden Hills field and three wells in the King’s Peak field are located in 6,200 to 7,200 ft [1,890 to 2,195 m] of water. These subsea wells produce into a common multiphase gathering system. Dual pipelines then transport produced gas to Canyon Station, a processing platform operated by Williams Energy Services, about 56 miles [90 km] away in Main Pass Block 261. Production is selectively controlled using an intelligent well completion system.

These fields comprise a series of high-permeability, unconsolidated sands overlying water-bearing sands in some areas. In addition, most of these reservoirs consist of multiple sands separated by shale layers. Production history from these types of reservoirs indicates that gas output drops quickly once water production begins.
Completing and draining multiple sands and having the capability of controlling water production without conventional remedial rig intervention were critical elements in the planning and design of these wells. Well-completion equipment consisted of a sump, or bottom, packer; AllFRAC screen assemblies and an isolation packer with tubing or annular isolation devices for each completion interval; and an isolation packer and upper completion equipment (previous page).

Total and Marathon completed a total of 13 perforated intervals in six subsea wells, four in the Aconcagua field and two in the Camden Hills field. Each well had at least two completion intervals that were frac packed with the objective of achieving completions skins of less than five.

Well operations, which were suspended after batch drilling all the wells, resumed by reentering the wells to drill out temporary cement plugs and replace mud with less damaging completion fluids. Surfactant pills were circulated to remove remaining mud deposits. Casing brushes, 360° scrapers, screen-type junk baskets and magnets removed any other debris. The subsea riser and cavities in the blowout preventer (BOP) stack were cleaned with brush and jetting tools.

Following these cleanout procedures, the wellbores were displaced with seawater followed by filtered calcium chloride [CaCl₂] brine to provide a 300- to 700-psi [2.1- to 4.8-MPa] hydrostatic overbalance. Total ran an ultrasonic cement bond log with a gamma ray correlation log and casing collar locator on the Total wells. Based on previous results, the Marathon well-completion program did not include a cement bond log. A lower sump packer run on wireline and set below the deepest perforations provided a reference depth for subsequent operations in all the wells.

Productive intervals were perforated with a 400- to 600-psi [2.8- to 4.1-MPa] overbalance using tubing-conveyed perforating (TCP) techniques. The relatively simple TCP gun assemblies consisted of a locating snap-latch, gun sections with charges loaded at 12 shots per foot (spf) and 120° or 60° phasing, a pressure-disk to hold fluid in the tubing and a hydraulic firing head with backup drop bar. One of the Camden Hills field wells used 18 spf. The wells were not flowed after perforating. This method proved to be simple, reliable and relatively low-risk compared to underbalanced perforating in unconsolidated sands.

Perforated intervals in the Aconcagua field ranged from 35 to 111 ft [11 to 34 m] in length with a true vertical depth (TVD) of about 12,700 ft [3,870 m]. Average reservoir pressure was 6,300 psi [43.4 MPa], and bottomhole static temperature (BHST) was 128°F [53°C]. Two zones had perforated interval lengths greater than 100 ft [30 m] with high inclination angles of 30° to 53°.

Productive zones in the Camden Hills field were close to a water contact, so fracture-height growth was a concern. Perforated-interval lengths varied from 46 to 65 ft [14 to 20 m] at a TVD of about 14,000 ft [4,267 m]. Reservoir pressure was 7,065 psi [48.7 MPa] and BHST was 155°F [68°C].

Because of high wellbore inclination angles in the Aconcagua field, Total selected wirewrapped Alternate Path AllFRAC screens with shunt tubes to obtain uniform fracture stimulation and complete packing of the screen-casing annulus across longer completion intervals. Marathon chose prepacked Weatherford screens with 20/40 mesh resin-coated proppant for the Camden Hills field where shorter completion intervals did not require the use of Alternate Path technology.

After perforating, the sand-control screen assembly for the lower completion interval, including an FIV Formation Isolation Valve tool, was run. Bottomhole temperature and pressure gauges were run to evaluate treatment placement.

In some cases, the average skin for conventional frac-packs in the Gulf of Mexico is greater than 10 (left). Total and Marathon applied optimized frac-packing techniques with the objectives of reducing completion skin and depleting these smaller fields more effectively without future remedial intervention.

Prior to frac-packing operations, Total and Marathon pumped 50 gal/ft [0.6 m³/m] of 10% hydrochloric acid [HCl] to remove perforation damage. Treatment fluids were selected based on cool-down temperatures of 87 to 95°F [31 to 35°C] using the CoolFRAC optimized fracturing service for high-permeability frac packs.

Before the main treatments, Total performed DataFRAC analysis that included ESR tests using a linear gel to accurately determine fracture-closure pressure. Subsequent injection-calibration treatments used a 20-pound per

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^ Frac-pack productivity. Gulf of Mexico pressure-buildup data indicate that completion skin is higher than expected in many frac-pack completions, leaving room for further optimization. In this evaluation, skins increased with increasing permeability-height (kh), averaging 10.3 for these 95 treatments.
thousand (ppt) crosslinked fluid. Marathon eliminated DataFRAC tests from Camden Hills field frac-pack procedures to avoid promoting fracture growth into nearby water sands.

Frac-packing treatments were pumped from the Schlumberger DeepSTIM I and DeepSTIM II stimulation vessels, which were moored alongside the Transocean Discoverer Spirit drillship (above). The main frac-packing treatments were performed at 20 to 30 bbl/min [3.2 to 4.8 m$^3$/min] using 20/40 man-made ceramic proppant and a 20-ppt crosslinked fluid.

After the operator encountered difficulty achieving a complete annular pack in the first Aconcagua well, perforation intervals were reduced to limit fracture growth into bounding shale layers and provide for continued fluid leakoff. Subsequently, a 120-bbl [19-m$^3$] slurry stage with 8 to 10 pounds of proppant added (ppa) per thousand gallons was included in the pumping schedule to allow for controlled reduction in injection rates at the end of a treatment. These steps ensured complete gravel packing on subsequent jobs without pumping separate treatments to top-off and pack the screen top.

In the Camden Hills field, Marathon and Schlumberger specialists designed unconventional frac packs using a less efficient crosslinked fluid to control fracture-height growth through excessive leakoff and to prevent fracture propagation into wet sands. Design fracture lengths were 20 to 30 ft [6.1 to 9.1 m] with a 1-in. propped fracture width. For the Aconcagua field completions, Total increased the polymer concentration slightly and designed fracture lengths of 40 to 50 ft [12.2 to 15.2 m].

Following frac-packing operations on the lower completion interval in each well, an isolation plug was set in the lower frac-pack packer. Sand or calcium carbonate pills were spotted on top of this plug to facilitate cleaning out debris after perforating the upper completion interval. The operators perforated the upper completion intervals, retrieved the packer isolation plug and ran sand-control equipment with an FIV tool before frac packing.

A seal assembly below the isolation packer connected into a polished-bore receptacle (PBR) at the top of the lower screen assembly. An AFIV annular-controlled FIV system in the isolation packer assembly provided flow isolation for the upper and lower completion intervals.

Zonal Isolation and Fluid-Loss Control
Canyon Express well designs integrated an FIV system with QUANTUM gravel-pack packer equipment for lower completion intervals. The sand-control equipment for upper intervals included an AFIV system. These devices assure a high level of well control without expensive and risky well-intervention operations. The FIV and AFIV systems have a proven record of providing safe, reliable zonal isolation in various drillstem testing and downhole tool applications.

These valves allow independent, two-way isolation and control of each interval to prevent fluid losses and gas influx during completion and flowback operations. The FIV and AFIV valves also facilitated pressure-integrity tests without wireline or coiled tubing intervention before the wells were opened for production.

In each of these Canyon Express wells, a shifting tool below the internal washpipe passed back through the screens as the gravel-packing workstring tubing was retrieved. This tool shifted a sleeve that closed the respective valves to isolate each completion interval after frac-packing treatments. The FIV and AFIV valves could also be opened with a similar shifting tool run on wireline or coiled tubing, and the FIV ball valve could be milled through tubing as a contingency.
Installing the isolation packer assembly after frac packing the upper interval mechanically shifted the upper AFIV open. A series of specific pressure cycles applied to the production tubing hydraulically opened the lower FIV device. This allowed the lower interval to be produced without intervention after the production packer and upper completion equipment were in place.

Reduced Completion Skins
During frac-packing operations, downhole gauges recorded and transmitted pressure and temperature data to surface. There was evidence of treatment fluids bypassing localized bridges through the shunts. There were also changes in the pressure-curve slope associated with variations in temperature, which indicated diversion through the shunts (top).

Fracture-closure pressures from conventional injection and minifracture tests were too ambiguous for critical ultradeepwater well completions. More reliable ESR analysis ensured optimal treatment designs and execution in the Aconcagua field.

Total performed Aconcagua field frac packs in circulating position and tracked bottomhole pressure (BHP) in real time by monitoring the tubing-casing annulus during the jobs performed in this field. Net-pressure gains of between 300 and 1,100 psi [2.1 and 7.6 MPa], indicating effective TSO results, were observed while pumping these optimized frac-packing treatments. Marathon performed Camden Hills field frac packs in squeeze position and did not monitor BHP using a live annulus. Calculated completion skins ranged from –1.5 to 4 with an average of 3.06 for 13 intervals in the six wells in Aconcagua and Camden Hills fields, much better than the previous average of 10.3 (below left). Production began just after the sixth well was completed. Effective TSO fracture treatments optimized production from frac-pack completions in high-permeability, unconsolidated formations. Each of the wells is capable of producing more than the target rate of 50 MMcf/D per well [1.4 million m³/d].

Successful TSO treatments in the ultradeepwater Aconcagua and Camden Hills gas fields were achieved through improved fluid designs and frac-packing procedures. Treatments designed to achieve TSO fractures took precedence over larger proppant volumes because placing more proppant does not necessarily impact frac-pack productivity significantly.

Treatment fluids were selected based on in-situ cool-down temperatures and shear rates inside the hydraulic fracture. In some cases, analysis of pretreatment injection-calibration tests using the new ESR method helped determine more accurate fracture-closure pressures.

Prior to executing frac-pack treatments, a sufficient volume of acid was pumped to ensure clean perforations. Alternate Path screens with shunt tubes facilitated treatment diversion in these multizone reservoirs with long completion intervals.

As in many endeavors, stimulation and gravel-packing improvements have evolved from a better understanding of basic principles and the refining of existing technologies and practices. Tested in this harsh ultradeepwater environment, these optimized techniques can be applied in other areas to ensure frac-packing success. —MET