HP/HT Challenges

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Our industry is faced with addressing new challenges in finding, appraising, and then exploiting HP/HT reservoirs. As the operating envelope continues to be stretched, new design and operational challenges are faced when contemplating new projects. Meanwhile, fields that have been put into production often will present problems not thought of before and, therefore, not accounted for in the original field-development plan.

We are finding that assumptions, practices, and designs that have served us well historically are no longer valid or fit for purpose for HP/HT wells. Because we must redesign existing downhole equipment and develop new equipment, we must maximize the use of modern design aids from the beginning of the design process to speed up the process and limit the risk of unexpected problems during product development and initial field application. There is one important aspect here: These modern design tools, such as finite-element analysis, while powerful, still require experienced engineers to ensure optimal application and benefit. So our need for high-quality engineers continues unabated. Many techniques such as perforating and production-chemical treatments must be re-examined carefully to ensure that they are applied properly to HP/HT wells because many assumptions and treatments that are used successfully in normally pressured wells at lower temperatures will prove inadequate in HP/HT applications and may result in considerable financial loss.

One area in which the industry appears to be going backward is in drilling, particularly in tripping performance. Anecdotal evidence indicates that tripping rates are half of what they were 20 years ago. There are good reasons for slower tripping rates in certain areas of any well, but a general reduction? Did mechanization of the rig floor cause this, or are other factors at work in concert with mechanization? It is strange that this is an area that has not come under pressure from operators, who are continually striving to improve performance in other areas of the industry, particularly with rig rates at the current high levels and drilling costs becoming a greater proportion of development costs. While newer techniques, such as casing while drilling and managed-pressure drilling, can contribute considerable cost savings, they are not universal and we should not ignore the basic methods by which the majority of wells are drilled.

The challenge continues and gets ever more interesting. **JPT**

HP/HT Challenges additional reading available at the SPE eLibrary: www.spe.org

SPE 108174 • *"Reducing Drilling Risks in a Highly Overpressurized Formation: A Case History in Nororiente Basin, Argentina" by M. Frydman, SPE, Schlumberger Geomechanics, et al.*

SPE 108656 • *"Harsh-Environment HP/HT Gas/Condensate Production Cleanup Experiences—Kristin Field" by Arild Fosså, Expro, et al.*

SPE 108432 • *"Dual Subsea Choke Applications for High-Pressure-Reservoir Development" by Weihong Meng, SPE, Fluor Corporation, et al.*

Have We Discarded Promising Squeeze Chemicals For High-Temperature Applications?

Selecting an effective scale inhibitor for a squeeze application at 170°C is no simple task. The traditional thermal-stability test by aging the chemical in bulk often is perceived as too harsh. An alternative of conducting the aging test inside core materials could be more representative of downhole conditions. The results from a recent investigation in which a scale inhibitor was aged by two methods, one in bulk as commonly practiced in the industry and one inside a sandstone core, demonstrated that the conventional method is unrepresentative. The study showed an unexpected relationship between desorption and inhibition effectiveness.

Introduction

In November 2005, Statoil commenced production from the Kristin field. Kristin is a high-pressure/high-temperature (HP/HT) gas/condensate field in the Haltenbanken area of the Norwegian Sea. The reservoir temperature is 170°C, and reservoir pressure is 911 bar. Producing by natural depletion and with the formation water containing in excess of 2,500-ppm calcium and 900-ppm bicarbonate, downhole $CaCO_3$-scale deposition is a major production problem. An active program to qualify suitable scale-control chemicals includes chemicals for squeeze treatment, wellhead continuous injection, and dissolver. Many squeeze chemicals were discarded because of their apparent thermal degradation at test conditions.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 105505, "Squeeze Chemical for HT Applications—Have We Discarded Promising Products By Performing Unrepresentative Thermal-Aging Tests?," by ***Rex Wat,*** *SPE,* ***Lars-Even Hauge,*** *SPE,* ***Kåre Solbakken, Kjell Erik Wennberg,*** *SPE,* ***Linda Merete Sivertsen,*** *and* ***Berit Gjersvold,*** *Statoil ASA, prepared for the 2007 SPE International Symposium on Oilfield Chemistry, Houston, 28 February–2 March. The paper has not been peer reviewed.*

The screening technique relied upon aging chemicals in a sealed container for a period of 7 to 21 days. The extent of degradation was measured by their performance relative to the fresh products. In earlier studies, the focus was on the effect of carrier-brine composition, pH, and oxygen level. The main degradation mechanisms were considered backbone scission and functional-group degradation that were caused by hydrolysis and free-radical attack.

While this approach was considered reasonable for the different products, doubt remained if this was representative of the field because the test was not within a rock matrix. The degradation mechanism of the molecules in a physically trapped environment was different from that being hindered by a surface-binding interaction. The conventional approach could overlook the most critical part of the degradation process for a squeeze chemical—the combined effect of thermal aging and surface-retention mechanisms. It is on this combined effect that this study focused.

Planning the Experiment

The aim of this project was to prove or disprove that a scale-inhibitor chemical that is adsorbed and thermally aged inside a core will retain its effectiveness more so than if it is aged in bulk. Considerations included the selection of chemical, pore volume of the core assembly, choice of core materials, type of brines, flooding sequence, and system integrity over an extended period of time.

Scale-Inhibitor Chemical. For this project, candidate choices were limited. Only chemicals that were "borderline" thermally stable at the test temperature of 170°C were considered. Chemicals considered thermally unstable at temperatures below 140°C by the conventional method (bulk test) were rejected. To simulate chemical return after a squeeze treatment, highest priority was placed on capturing effluent samples toward the end of the desorption stage (i.e., the later part of the squeeze life). In addition, the concentration of the scale inhibitor in these effluents must be high enough to facilitate meaningful performance tests. Therefore, a concentration range of 50 to 500 ppm was considered most desirable. The scale inhibitor required good adsorption/desorption characteristics. Chemicals that adsorbed poorly were rejected because the associated desorption profile would be short and abrupt.

Core Material. Berea and Bentheimer outcrop cores were evaluated for use in the experiment. The main selection criterion was clay content, thereby maximizing the available adsorption sites for the scale inhibitor. Berea core was selected because it had the higher clay content as well as the lower permeability, 200 md.

Brine Selection. Various brines were used in the different stages of the experiment. A 10% scale-inhibitor solution was made up with 6% NaCl as the carrier brine. A 200-ppm oxygen scavenger was included in the mix. For the postflush period, the brine had a salinity level similar to the original formation water. It contained 1,500-ppm calcium and 250-ppm bicarbonate and had a saturation ratio of 19. More importantly, this brine had a blank scaleup time of 35 to 65 minutes and a minimum inhibition concentration of approximately 10 ppm. This brine was inherently unstable at room temperature and would form $CaCO_3$ prematurely within

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

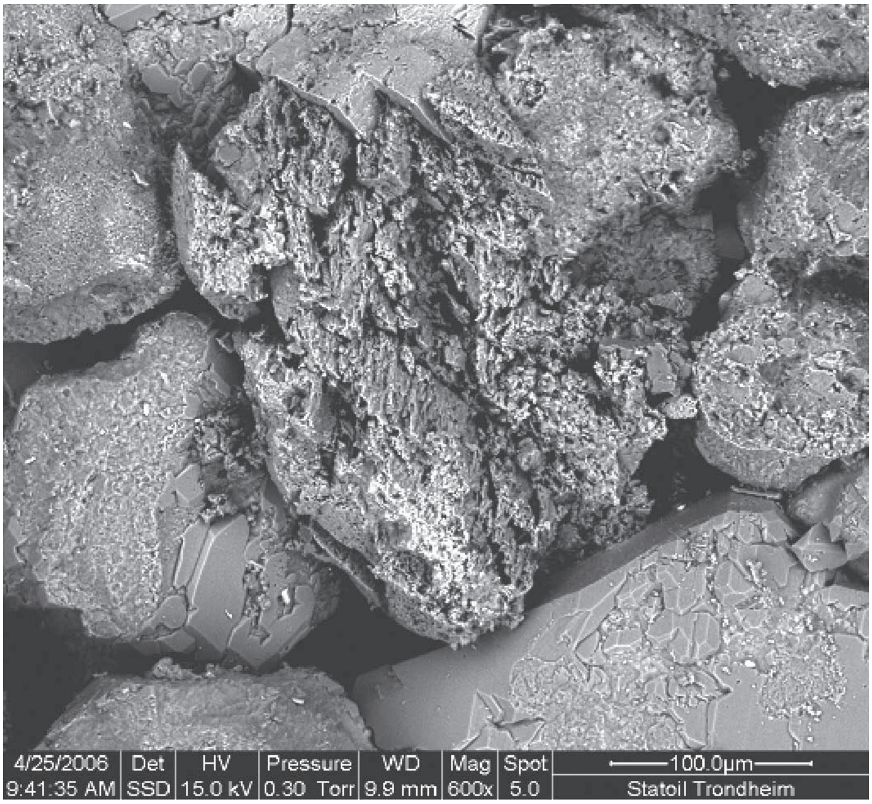


Fig. 1—ESEM picture from the middle part of the core with some dissolution of the clay.

the injection system. It was decided to split this brine into a cation brine (Brine A) and an anion brine (Brine B) and use Brine A for the post-flush.

System Integrity. The main shut-in period was planned for 1 month, but the duration of the whole experiment at 170°C was anticipated to be much longer. The desorption phase was truncated into multiple post-flush/shut-in steps. Instead of completing the entire desorption phase uninterrupted and storing the samples for later use, it was decided to shut in the core after 5 to 10 pore volumes (PV) of effluent was obtained for analysis/performance tests. This method prevented contamination or oxidation of samples if they had been left idle. This method also helped preserve the chemicals and keep them inside the core. Sampling and testing freshly desorbed samples provided accuracy, with the thermal-aging periods ranging between 55 and 110 days.

The desorption phase was expected to last several weeks at 170°C, and the core apparatus was left unattended for most of that time. Therefore, several monitoring and corrective actions were put in place. A pump, operated in both injection and extraction modes, was used to maintain a constant pore pressure during the shut-in periods. With the outlet valve closed, any leakage upstream of the inlet valve could be compensated for. The volume throughput of the pump during this period was monitored continuously. During the main 55-day shut-in period, a volumetric compensation of +3 mL was recorded, which had been identified earlier as a microleak at one of the injection valves. The data-logging computer was programmed to deliver warning messages and readout by use of a mobile phone according to the preset values. The full-length paper details experiment procedures.

Results and Discussions

The core test lasted 156 days, of which 116 days were operated at 170°C. The chemical was injected, shut in, and desorbed as planned. The differential pressure of the core was monitored throughout the experiment. Most importantly, the differential pressure for the entire 56-day post-flush period remained constant, indicating that the core was not affected adversely by the 55-day shut-in period when it was in contact with the concentrated chemical or by the multiple shut-in/post-flush stages that followed.

Before the post-flush period, a baseline performance test with fresh scale inhibitor was carried out. However, when a sample of the stock solution (10% silica in 6% NaCl and 200-ppm oxygen scavenger) was mixed with Brine A, an unexpected precipitation occurred. Earlier compatibility studies had not shown any problems between the silica and Brine A, nor between the silica and the oxygen scavenger in 6% NaCl. Subsequent investigation identified that the precipitation was caused by the reaction of SO_4 with barium and calcium in Brine A. The SO_4 originated from the stock solution and was the reaction product of the bisulfide-based oxygen scavenger following the removal of oxygen. To avoid possible precipitation inside the core, a 1.1-PV 6% NaCl spacer with no oxygen scavenger was injected at the start of the post-flush period. This step prevented direct contact between the shut-in chemical with the unexpected SO_4 and Brine A that was being injected. The rest of the desorption phase progressed as planned.

Chemical Performance. A baseline was established without the use of scale inhibitor. Approximately 35 to 65 minutes were required for the coil to scale up with a 50:50 mix of Brines A and B. All runs were characterized by an abrupt rise in pressure response. A reference was set by use of fresh chemicals. At 2 ppm, the scale inhibitor had no effect on the efficiency tests. At 5 ppm, a small positive effect was observed, whereas 7 ppm doubled the scaleup time to approximately 2 hours. For the reference concentration of 10 ppm, the scaleup time was 6.5 to 7.5 hours.

For chemical aged 45 days in bulk (in ampoules), the aged 10-ppm chemical had a scaleup time of 1 to 1.5 hours. At a concentration of 15 ppm, the ampoule sample had a scaleup time of 4 to 5.5 hours, still considerably less than that achieved by the reference sample.

For chemical aged in the core, samples taken during the coreflood were diluted and efficiency tested in the same manner as the samples aged in the ampoules. The length of thermal treatment on the chemical in the core varied depending on when the sample was produced. Because precipitate formed upon cooling, effluents

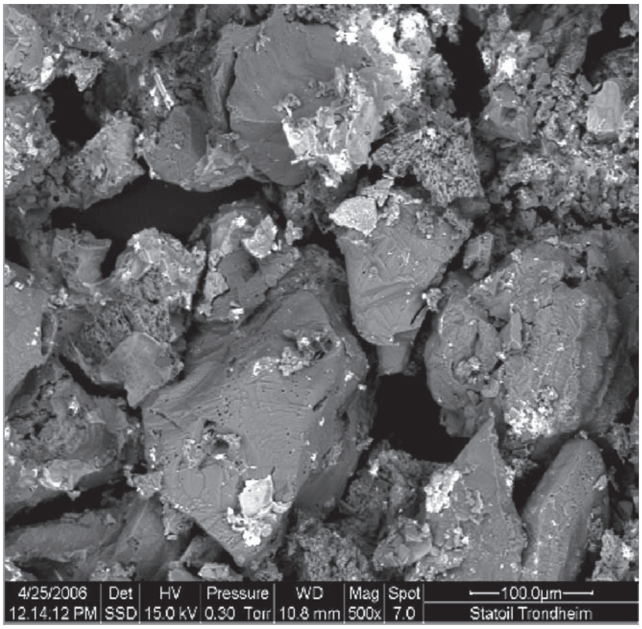


Fig. 2—ESEM picture from the front of the core, showing that much of the clay is dissolved.

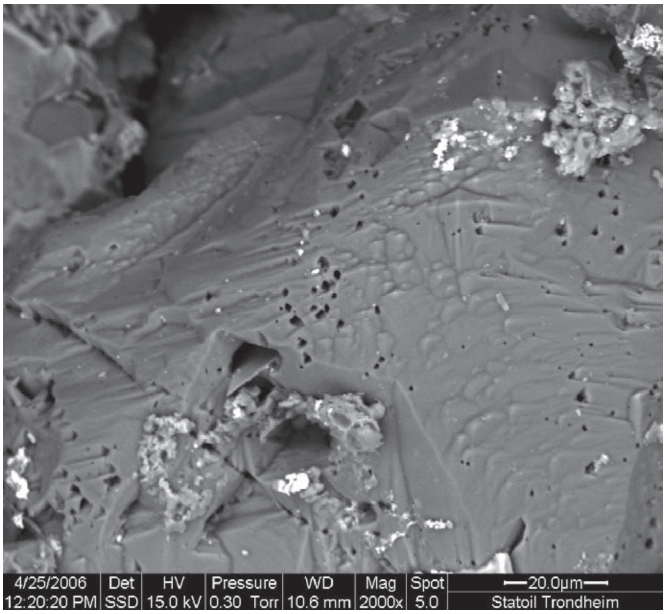


Fig. 3—ESEM picture of silica particle from the front of the core.

from the early post-flush phase were not used. The first batch of sample collected for the efficiency test was aged 84 days, equivalent to 50 PV of post-flush. At 10-ppm concentration, this sample had a scaleup time of approximately 2.5 hours, a noticeable improvement from that of the ampoule sample. Six further samples collected between 84 and 110 days were tested at 10-ppm concentration. These data showed that the aging process inside the core was less severe than that in bulk, which led to the chemical retaining more of its effectiveness. While the scaleup time was 1 to 1.5 hours for the ampoule sample, scaleup time extended to 2.5 to 6 hours for samples aged inside the core. It was interesting to note the apparent improved efficiency of samples that desorbed from the core later. A possible explanation is that the interaction between the fluid molecules and the rock substrate. The stronger the interaction with the rock matrix, the slower the fluid molecules would desorb. At the same time, the fluid molecules would be more sterically protected and hindered from thermal degradation. The last two samples (i.e., 104 and 110 days corresponding to 110 and 200 PV, respectively) did show poorer performance and a reversed trend. Analysis by the phosphomolybdenum blue method, which was carried out independently, confirmed the higher percentage of "broken" molecules at 200 PV. The cause of this degradation is not fully understood and will be investigated further in a future project. Note that the shut-in/post-flush sequence was switched to continuous mode after 67 PV.

Despite the spread in the experimental data, the results demonstrated that samples aged inside the core remained more effective compared with those aged in ampoules. This result was achieved despite all the samples from the core being aged longer.

Post-Treatment Core Analysis. Because of the high level of silica and aluminum detected in the early effluent samples, additional core analyses were carried out. After dismantling the experiment, the core was cut into four sections. Sections 1, 2, and 3 were sent for strength analyses. The reference sample was an unused section that was trimmed from the core before it was mounted. Results show that there had been a considerable reduction in strength in the front, but the middle and outlet sections had retained their strength.

Section 4 was crushed and environmental-scanning-electron-microscope (ESEM) pictures were taken of the fresh surface, **(Fig. 1).** In addition, pictures were taken of the sand particles from the front part of the core **(Figs. 2 and 3).** Small wormholes were observed in the silica particles, unlike a normal smooth silica surface. When comparing Figs. 1 and 2, the dissolution of core material (particularly of the clay minerals) in the front section of the core becomes evident.

Conclusions

- The conventional method of thermally aging chemicals in a bulk solution may not be appropriate for screening chemicals for downhole-squeeze applications because the extent of degradation is different with or without the presence of a rock matrix.
- Traditional aging in a bulk solution seemed to be too harsh compared to aging inside a core because the fluid molecules that were adsorbed or that interacted with the rock substrate appeared to retain most of their inhibition efficiency.
- Performance tests indicated that the scale inhibitor aged in the glass ampoules (bulk) for approximately 45 days had lost more than 60% of its effectiveness as a scale inhibitor.
- However, the chemical aged inside a core for up to 110 days had lost an average of only 33% of its efficiency.
- There was evidence to suggest that efficiency retainment increased with the length of adsorption (i.e., fluid molecules desorbed later were more tightly bound to the rock substrate and, thus, were better protected from the degradation process).
- The differences in performance could be attributed to the changes in the molecular structure.
- The extent to which the rock substrate can hinder the degradation process will be different for the different chemical species and for different rock compositions. **JPT**

Challenges of Designing HP/HT Equipment

The full-length paper presents an overview of the main design activities for a completion and intervention landing-string system. The functional- and structural-design challenges encountered because of the high operating pressures and temperatures are reviewed. Analysis tools were used to quantify the observations found during testing, and subsequently to assist in determining a design solution. A key aspect of the design process was viewing the design and operations from a holistic perspective by evaluating the design throughout its operational life.

Introduction

The full-length paper details the technical challenges of developing a high-pressure/high-temperature (HP/HT) completion and intervention landing-string system for the Tahiti field in the Gulf of Mexico (GOM). Because the project presented some specific operational challenges, traditional analytical methods were insufficient for the design process and a comprehensive test and qualification program was required to validate that the equipment proposed was fit for purpose. The full-length paper presents an overview of the design methodology adopted and how the results from finite-element modeling assisted in validating the test program.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 109999, "The Challenges of Designing HP/HT Equipment," by ***Andrew Forsyth,*** *SPE, Expro;* ***Brian Saucier,*** *DeepMar;* ***Daniel More,*** *Expro;* ***Ray A. Stawaisz,*** *Chevron;* ***Dave Gill,*** *Stress Services; and* ***Ray Younger,*** *Prospect, prepared for the 2007 SPE Annual Technical Conference and Exhibition, Anaheim, California, 11–14 November. The paper has not been peer reviewed.*

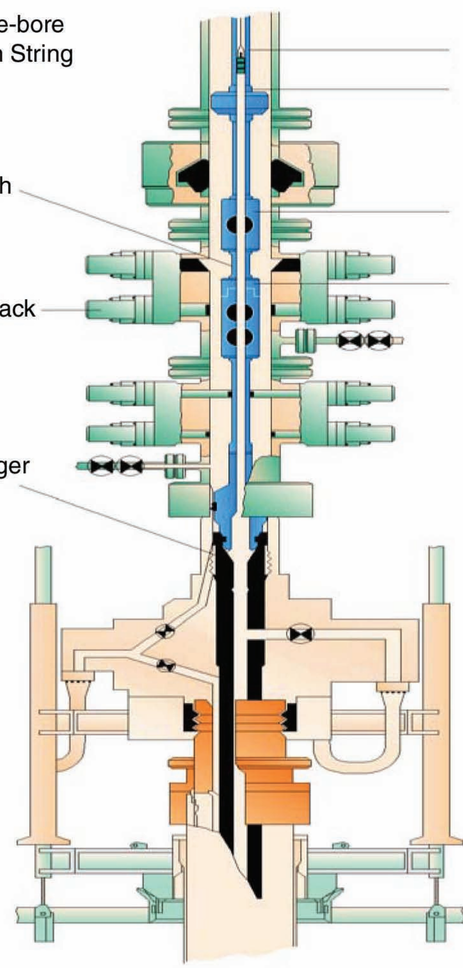


Fig. 1—Landing-string configuration.

Fig. 1 shows a typical subsea landing-string configuration within a blowout preventer (BOP). The hydraulic-controlled functions of the subsea test tree (SSTT) are the following.

- To provide a dual-barrier well-isolation system during completion and intervention operations.
- To allow coiled tubing (CT) and wireline access into the well and to cut CT and wireline in an emergency situation without compromising pressure containment.
- To disconnect the upper landing string from the SSTT by means of a latch mechanism.
- To retain hydrocarbons in the landing string in the event of shear or planned disconnect.
- To provide a method of closure of the BOP rams on special joints for HP well integrity.

The SSTT comprises the latch assembly, dual fail-safe closed ball-valve assembly, and a slick-joint assembly to facilitate closure of the BOP pipe rams.

With the introduction of subsea horizontal trees in the mid-1990s, landing-string systems were developed for well-completion and -intervention operations. Early landing strings were designed to operate at maximum differential pressures and temperatures of 10,000 psi and 250°F, respectively. With the discovery of significant hydrocarbon reserves in deep water, the challenge to develop economically viable equipment had been set. Along with the requirement for HP/HT applications, the locations and environment that landing strings are required to operate in have become significantly more arduous. The HP/HT landing string also was required to be controlled with a subsea electrohydraulic control system for the deepwater application as opposed to earlier systems that were operated hydraulically from surface.

Design Approach

The traditional approach to functional design was to use experience of previous designs and modify the equipment to account for the new, more arduous working environment. This is essentially an iterative and to some extent intuitive process. Functionality then was demonstrated by test.

During the Tahiti project, a number of functional-design features were identified during testing as potential areas of operational risk. To quantify these risks, the decision was made to perform detailed finite-element analysis (FEA), focusing on the functionality of the equipment to ensure that both the design-project activity and the operational risks were reduced.

By using FEA, the parameters of interest such as pressure or temperature can be modified. Examination of a particular component in the assembly in relation to its adjacent members can be performed and a quantitative understanding of its relative displacement obtained.

During factory acceptance testing of the SSTT, malfunctions occurred during the fail-safe closure sequence of the upper and lower ball-valve mechanism at the full rated working pressure. On inspection of the assembly, it was concluded that as a result of differential pressure across the production piston, the expansion was sufficient to cause the glide rings to bind up on the main housing. This resulted in a detailed investigation, a major part of which was FEA.

Structural and thermal FEA was conducted to evaluate the behavior of critical internal components of the SSTT. Hot well-production fluid flows through the central bore of the SSTT, while the temperature of the outside surface is determined by seabed temperatures. As a result, there is a thermal gradient between the inner and outer surfaces of the assembly.

The components of the assembly move axially relative to one another. This is achieved by hydraulic pressure, and thus seals are in place at various locations. At the location of the hydraulic seals, the hydraulic control fluid and the well production are mutually isolated.

The assembly consists of a series of steel-alloy cylinders of varying lengths, with relatively high conductivity, separated by annular spaces filled with hydraulic fluid having a thermal conductivity that is significantly lower than that of the steel components. This leads to complex heat paths.

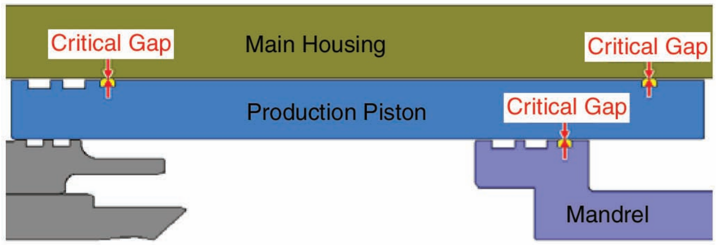


Fig. 2—Assembly showing glide-ring location.

The low conductivity of the hydraulic fluid in the annular spaces between components means that significant temperature differences arise between the components inside and outside the hydraulic gap. This gives rise to differential expansions, which change the clearances between components. In some instances, the expansion at the production-piston glide rings, which have a small initial clearance, is sufficient to close the gap, bringing the glide rings into contact with the main housing.

Summary of SSTT Analysis

The structural and thermal analysis evaluating the displacement effects of both internal pressure and nonuniform temperature distribution considered the SSTT ball valve in the open and closed positions. It was found that the open position was critical, from a functional aspect, because of the applied-pressure distribution. Also, the thermal gradient is more significant when the well is flowing. Hence, for illustrative purposes, this review is limited to the SSTT ball-valve-open case. One of the main concerns was the load imparted by the piston glide rings on the main housing and how this could affect functionality.

Pressure Analysis. The pressure-load case applies 15,000 psi and 0 psi to the internal and external surface, respectively. **Fig. 2** shows a schematic of the critical components in the pressure analysis, with the glide rings shown in yellow. For a 15,000-psi internal pressure, the upper and middle glide rings are in contact with the main housing. The radial contact force was determined from the analysis, and by use of a representative value for the coefficient of friction, the axial resistance force was quantified. The next step was a sensitivity analysis to determine the effect of modifying the glide-ring configuration. As a result of these analyses, the decision was made to reduce the upper-glide-ring diameter and rerun the model. The modification showed that the contact force at the upper glide ring was decreased to a value that was considered acceptable.

Because of the increased operating pressure, the original glide-ring dimensions cause significant interference, resulting in large contact forces, which compromised the functionality of the SSTT. The decision was made to modify the design by removing the middle glide ring from the assembly and reducing the diameter of the upper glide ring. The pressure analysis then was repeated with the modified geometry to determine the new contact loads. These modifications were incorporated into the design, and the SSTT underwent extensive testing, which was completed successfully.

Thermal Analysis. The thermal-load case reviewed considered an applied internal and external surface temperature of 250 and 41°F, respectively. A graph of thermal expansion of the SSTT is shown in Fig. 10 in the full-length paper for two load cases, open-water and in the BOP/marine riser. The BOP/marine-riser model is applicable for this analysis. It can be seen that the two fluid interfaces at the inner and outer surface of the main housing have a significant effect on the expansion of the SSTT components. The fluids, at these two locations, act as thermal insulation, reducing the differential expansion of the components. From this information, the robustness of the design with respect to temperature was determined.

The internal temperature increases the absolute expansion of the components. However, the relative expansion determines the effect on functionality of the SSTT ball valve. The analysis demonstrates the importance of considering the fluid layer because it plays a critical part in minimizing the effect that the high internal temperature has on functionality. The analysis demonstrated that the effect of temperature, although important, was not as significant as that of pressure.

For completeness, the combined analysis incorporates both the pressure and temperature analysis. As would be expected, the contact load at the upper glide ring is larger than the pressure alone, but still is considered within acceptable limits.

Operational Performance

The initial deployment of the landing-string system was for flowback operations on the Chevron Tahiti project in the GOM. These HP/HT wells are in approximately 4,000 ft of water and use dynamically positioned rigs. The risk of a station-keeping event drove the requirement for an electrohydraulic control system, and the high differential pressures expected at Tahiti precluded use of the available 10,000-psi landing-string systems. A $6^1/_8$-in. nominal bore was required because of the crown-plug size for the horizontal tree hangers.

The Tahiti project conducted multiple batched flowbacks from two rigs sharing an integrated backup system. Each rig initially had a different BOP configuration, which would have prevented the use of a single backup. Management of this was achieved by installing special adapters into the rigs' BOPs before startup of the completion operations to allow a single landing-string system to be interchangeable.

The continuous operations schedule, coupled with joint barge and DP Class III rigs, demanded that the landing string have high system integrity and a fast response time. The systems were tested fully during the system-integration test in late 2006 and early 2007 and were deployed in March 2007 and May 2007. The system was tested functionally on deck and pressure tested subsea before each well-flowback operation. Well-flowback rates were limited to an 8,000-BOPD sustainable maximum rate because of the surface separation system aboard the rigs. **JPT**

High-Pressure/High-Temperature Consolidated Completion in the Gulf of Mexico

Decades after the first completion in the Gulf of Mexico (GOM) continental shelf, the logical expansion of these mature assets has extended into reservoirs that are deeper, hotter, and higher-pressured than wells completed previously. These high-pressure/high-temperature (HP/HT) wells can cause extreme completion challenges. HP/HT formations also tend to have low permeabilities, which is the opposite of most GOM reservoirs. To make these low-permeability formations economical in an offshore environment, it is imperative that stimulation treatments be completely effective.

Introduction

The West Cameron 62 field, on the continental shelf just south of Louisiana at a water depth of 35 ft, had its first well completed more than 20 years ago. Since that time, more than 30 different intervals have been completed at depths ranging from a few thousand feet to more than 10,000 ft. In recent years, it has become necessary to focus on reservoirs that exist in the 18,000 to 20,000 ft true vertical depth (TVD) range. At these depths, the pressures and temperatures of the formation trend toward the limit of what current technology allows when completion equipment and fluids are considered. The West Cameron 62 Well A-2 was completed at these depths in the Cris R formation.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper OTC 18976, "High-Pressure,High-Temperature Consolidated Completion in the Continental Shelf Environment of the Gulf of Mexico: Case History," by ***Richard E. Patterson,*** *SPE, and* ***Trevor J. Willms,*** *SPE, El Paso E&P, and* ***Keith Foley,*** *SPE, and* ***Jason Edwards,*** *SPE, Halliburton, prepared for the 2007 Offshore Technology Conference, Houston, 30 April–3 May. The paper has not been peer reviewed.*

The Cris R sand is located between 17,843 and 18,021 ft TVD, which correlates to 19,789 and 19,976 ft measured depth (MD), respectively. The initial bottomhole pressure (BHP) for the Cris R formation was measured at 16,500 psi at midperforation. The bottomhole temperature (BHT) at midperforation was 356°F.

Contrary to conventional GOM reservoirs, which typically have average permeabilities greater than 50 md, the permeability of the Cris R sand averaged only 0.64 md. The 18% porosity also was significantly lower than that of the well-sorted formations found at shallower depths. In fact, along with permeability and porosity, the rock mechanics falls more in line with typical south Texas "hard rock" reservoirs such as the Wilcox and Frio formations.

Despite the low permeability and porosity, the production of the well before the hydraulic-fracturing treatment was 12.0 MMscf/D and 396 B/D of condensate at a 8,572-psi flowing tubing pressure (FTP). Use of fracture models and nodal analysis led to the belief that the production rates could be increased by at least two-fold through implementation of a hydraulic fracture. However, very little information on HP/HT fracturing treatments in the GOM was available.

HP/HT Well Completions

HP/HT wells are sorted into four main categories.

- Green—BHP between 17,000 and 22,000 psi; BHT between 350 and 425°F.
- Yellow—BHP between 22,000 and 25,500 psi; BHT between 425 and 485°F.
- Orange—BHP between 25,500 and 28,500 psi; BHT between 485 and 515°F.
- Red—BHP above 28,500 psi; BHT above 515°F.

Currently, the service industry is able to offer solutions only for formations in the Green and Yellow categories. However, equipment in the Green category has a delivery time of more than 12 months, and equipment in the Yellow category is available in limited sizes and would require years for design, testing, and delivery of additional sizes.

Completion Method

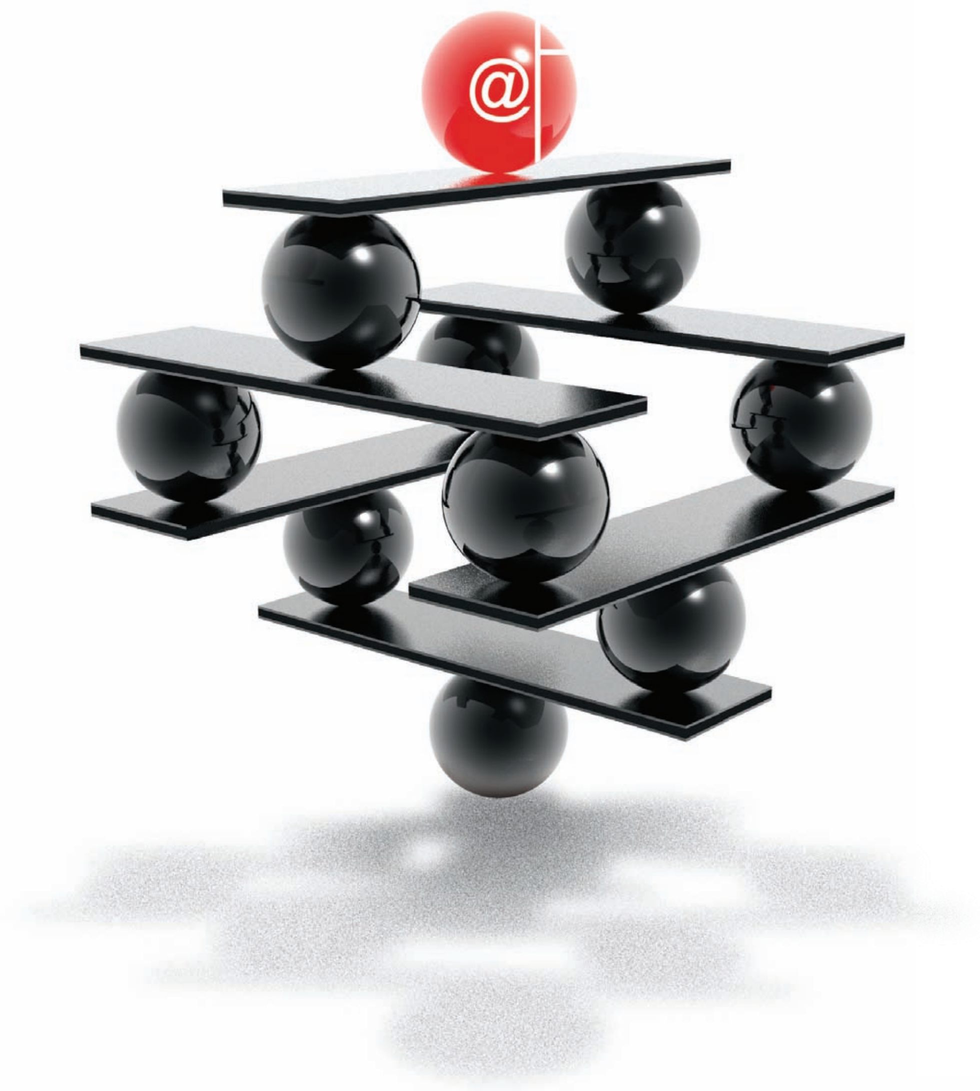
The completion concept for Well A-2 was a 4^1/2-in. monobore natural completion because sand control was not deemed necessary, high production rates were anticipated, and the potential to fracture down the production string was realized. A 7^5/8×9^5/8-in. swaged liner tieback was used to accommodate the 4^1/2-in. surface-controlled subsurface safety valve. Because a natural completion was planned, the well was perforated underbalanced using wireline guns at 6 shots/ft (SPF) with 60° phasing.

Because of the low stress contrast between the sand and shales, it was planned to produce the well for some period of time before fracturing. After 2 months, the FTP for the well had decreased significantly, creating a contrast in stresses between the shale and sand for better fracture containment.

Fracture Design

With the knowledge that this would not be a conventional GOM soft-rock, normal-pressured frac pack, many factors entered into determining the best method for stimulating the reservoir.

The full-length paper is available for purchase at the OTC Library: www.otcnet.org.



Engineers reviewed analogous wells in south Texas to capture best practices for dealing with HP/HT hard-rock hydraulic fracturing. Industry experts were consulted to help ensure that the Well A-2 fracture treatment would be a success.

Software Design

Production rates and net present value were evaluated with various fracture geometries, conductivities, and drawdown pressures. The greater the fracture length, the higher the production, with diminishing returns with half-lengths greater than 150 ft.

It was estimated that a fracture would result in an initial three-fold increase in productivity, with a sustained two-fold increase. The initial goal was to create a fracture with half-length of appproximately 150 ft and a proppant concentration greater than 2 lbm/ft^2.

A closure stress of 17,245 psi was calculated from the Eaton stress equation. The boundary layers were expected to have closure pressures of 17,307 and 17,633 psi, resulting in a stress contrast between sands and shales. Modulus information came from dipole sonic logs previously run in the well. The assumed modulus through the sands was 2.5E06 psi, while the assumed modulus through the bounding shale layers was 2.2E06 psi.

A further study of fracture half-length and height vs. pad size was performed. The results yielded very little half-length gained beyond the 20,000-gal pad size at 30 bbl/min. In both instances, the added pad contributed more to height growth than to length. This is largely because of the inverted modulus of the sand and shale and the small differential in stresses between the two. Increasing the rate to 45 bbl/min did increase the fracture half-length by 10 ft.

Table 5 in the full-length paper shows the planned pumping schedule. The proppant schedule started with a 0.5-lbm/gal stage and increased to a maximum 8-lbm/gal proppant. The design injection rate was 45 bbl/min. The resultant treatment called for 68,000 gal of gel and 203,400 lbm of 20/40-mesh, high-strength proppant. The decrease in net pressure to start the job is indicative of height growth. Following the tip-screenout event seen at the 30-minute mark, there is a slight rise in the net pressure indicative of the 0.44-in. width generated in the design. The drop in net pressure at the end is fluid leakoff after pump shutdown. The final dimensions of the designed fracture were a 157-ft propped half-length and a 621-ft maximum height at the wellbore, giving an average conductivity of 2,200 md-ft with an average in-situ concentration of 1.8 lbm/ft^2.

Fluid/Proppant Selection

The biggest issue with pumping the hydraulic-fracturing treatment for a HP/HT well, especially when there is no need for sand control, comes in finding a fluid that can open the formation effectively at the high temperatures. To do this, a specialized fluid was used that could operate at extreme temperatures. The fluid used was a high-temperature fracture fluid that uses low polymer-gel loading and an optimized crosslinker system. The high-temperature fluid (HTF) has a very predictable viscosity and efficiency and tends not to “thermally thin” as quickly as other fracture fluids. The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lower base-gel concentration yields greater regained permeability of the proppant pack. The fluid is applicable in reservoirs with temperatures ranging from less than 275 to 425°F, which made it applicable for Well A-2. The HTF also was salt tolerant, so the ability to inhibit clay swelling, which was a priority, was still available.

Given the high pressures and depletion-drive nature of the formation, it was estimated that abandonment pressure of the well would be 2,000 psi using a 90% depletion factor. This meant that a maximum stress of 14,000 psi was placed on the proppant toward the end of the life of the well. To mitigate proppant crushing, it was necessary to use a high-strength proppant that could maintain a high conductivity as the stresses upon the pack increased. The proppant chosen came in a 20/40-mesh size and would experience only 2.7% crushing at 15,000 psi. Because of this crushing resistance, the retained conductivity at 2 lbm/ft^2 was still an impressive 2,140 md-ft. Furthermore, the beta factor of the proppant was a low 0.00077 $atm\text{-}s^2/g$.

One other consideration was the need to mitigate the flowback of proppant to help ensure that the conductivity in the fracture remained intact and to help prevent damage to the surface production equipment. Application of a surface-modifying agent (SMA) provided mitigation against the flow of proppant out of the formation and into the production stream. The SMA applies as a tacky substance that, once bonded to the proppant, will not come off onto any other object. Once the SMA-coated proppant packs in the fracture and is subject to the static BHT, it will harden and prevent flowback of any proppant into the wellbore.

Treatment Results

During the main treatment, 84,042 gal of crosslinked 45-lbm HTF, carrying 221,225 lbm of SMA-coated 20/40-mesh proppant, was pumped and displaced with 10,943 gal of 45-lbm linear gel. The job was shut down with the flush fluid 10 bbl from the top of the perforations. Maximum proppant concentration at the perforations was 8 lbm/gal. The propped length of the fracture was calculated to be 165 ft, with a 0.51-in. average width. The actual net pressure increase was estimated to be 344 psi.

The job placed a total of 216,252 lbm of 20/40-mesh proppant in the formation. This was equivalent to 1,215 lbm/TVD ft of perforations. The maximum surface pressure was 13,400 psi, and approximately 7,000 psi was kept on the annulus throughout the job to limit tubing movement. The total fluid pumped was 112,419 gal, and 4,973 lbm of proppant remained in the wellbore when the pumps shut down.

Final Design

With the fluid, proppant, and SMA determined, the service company processed the final design through a 3D fracture simulator one last time to ensure optimum fracture geometry and conductivity. On the basis of these modeling results, the well was hydraulically fractured after 2 months of production. Nodal analysis indicated that the hydraulic fracture created an initial 5-fold increase in well productivity, with a sustained 6-month increase of approximately 2.5-fold. **JPT**

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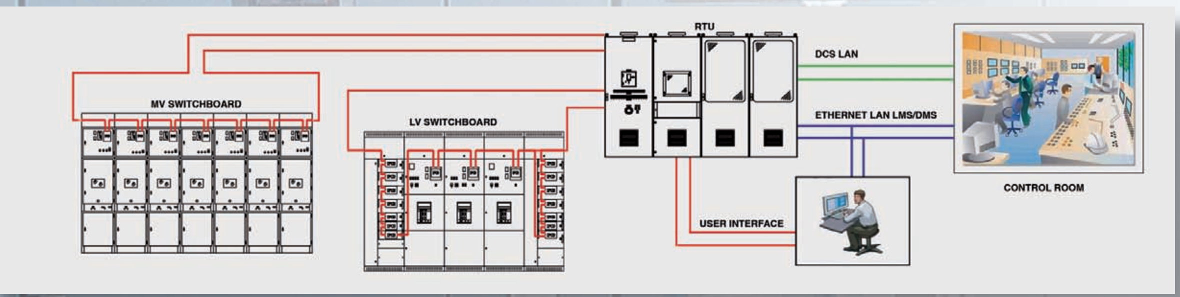

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