Tahiti field requirements prompt development of ultra-high pressure completion tubular

By Richard C. Griffin, R. Brett Chandler, Andrei Muradov, Michael Jellison, Grant Prideco; J. Rodney Hensley, Manuel Gonzalez, Chevron

THE TWO-YEAR comprehensive effort to design, test, manufacture and implement a high-pressure completion tubular for **ChevronTexaco**'s Tahiti project resulted in several enabling technologies, including a premium seal, rotary-shouldered connection to withstand absolute pressures up to 29,000 psi, metallurgical and heat treatment advances to permit manufacture of ultra-high strength tool joints and an industry-first rotary-shouldered connection testing program consisting of simultaneously applied internal and external pressures with temperature, bending, tension and compression loads.

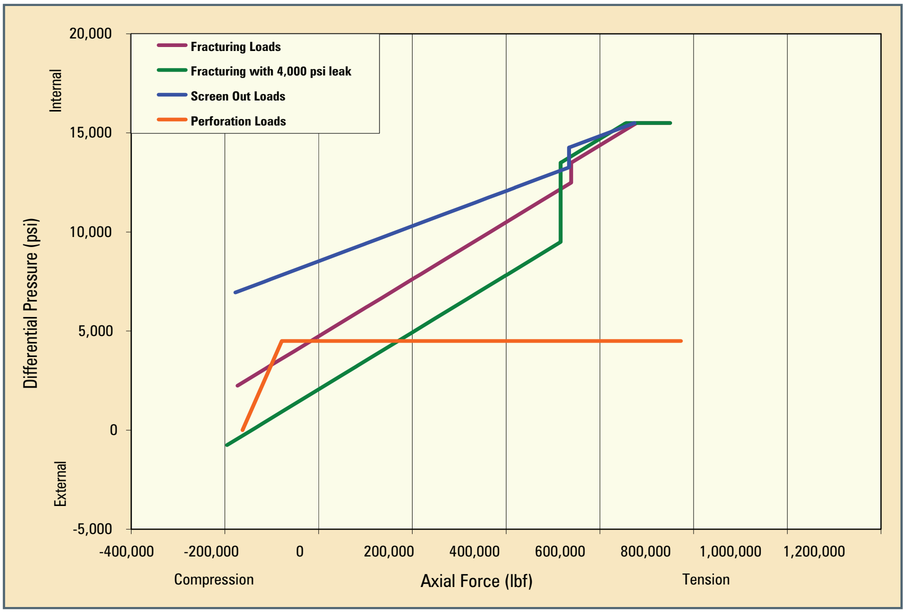
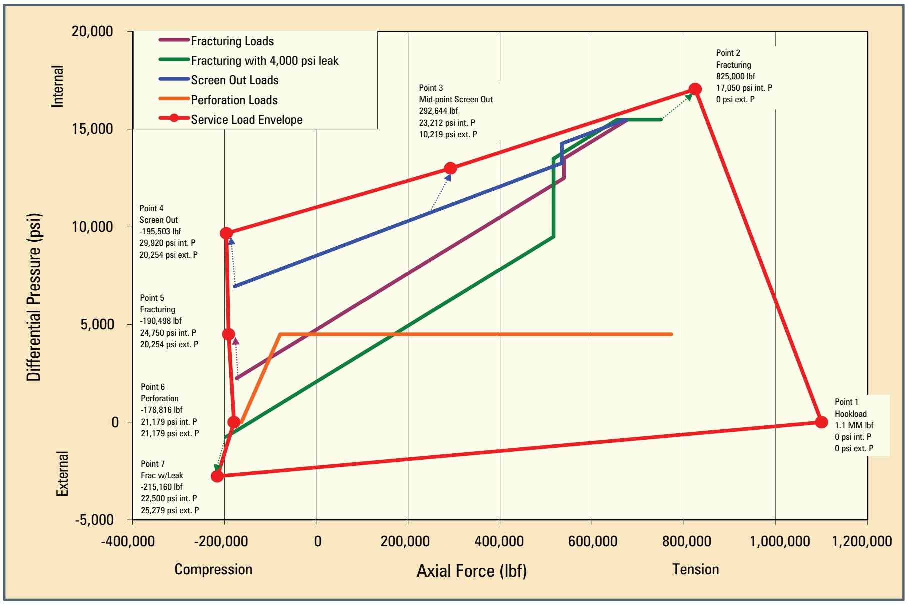


Figure 1 (above): Calculated load cases for Tahiti completion operations (fracturing, fracturing with 4,000-psi leak, screenout and perforation) using 5 $^{7}/_{8}$-in. CT-M57 from surface to 26,500 ft TD. Figure 2 (below): Service load envelope with seven load points encompasses the four load scenarios for Tahiti completion operations.



BACKGROUND

Located in approximately 4,000 ft of water in the Gulf of Mexico (GOM), ChevronTexaco's Tahiti prospect is one of the most significant oil discoveries in the history of the deepwater Gulf. Tahiti well depths are in excess of 28,000 ft, creating challenging conditions for high-pressure, subsea completion operations. A major challenge was the design, testing and manufacture of a subsea completion string that would provide efficient hydraulics during fracturing operations while ensuring mechanical and pressure integrity to absolute pressures up to 29,000 psi during screen-out.

Similar wells have been completed with up to four outside diameter (OD) tapered strings, which limit the treating rate during the fracture stimulation and often yield a less desirable fracture network, potentially reducing the well's production capability. To maximize Tahiti's production rates, a fracpac completion was selected to create an extensive fracture network in the highly overburdened formation. Treating rates during the fracpac were deemed critical for the 17,000-plus psi treating pressure. A large-diameter completion tubular and a new connection that could meet all loads from top to bottom were required.

TAHITI FIELD

The Tahiti prospect was generated using an advanced seismic depth-imaging technique proprietary to ChevronTexaco. It allowed improved clarity of the Tahiti architecture through more than two miles of salt layers, thereby enabling precise positioning of the first exploratory well.

In March 2002, ChevronTexaco drilled the Tahiti #1 well in 4,017 ft of water to a total depth (TD) of 28,411 ft. It was located approximately 190 miles southwest of New Orleans in Green Canyon Block 640. Results indicated the presence of high-quality reservoir sand with a total net pay of over 400 ft. Two appraisal wells were then drilled simultaneously in Green Canyon blocks 596 and 640. The two-well appraisal program confirmed the reservoirs were well developed and correlated over a three-mile distance. Results validated the hydrocarbon reservoirs found in the discovery well, with one appraisal well encountering more than 1,000 ft of net pay in high-quality sandstones.

The appraisal program verified ChevronTexaco's initial estimates of 400 million to 500 million barrels of ultimate recoverable oil reserves, one of the most significant net pay accumulations in GOM history. A well test of the Tahiti #1 discovery well was planned for the second quarter of 2004. To complete the discovery well, the Tahiti Well Test Team faced several challenges.

COMPLETION CHALLENGES

Due to the reservoir's extreme depth and bottomhole pressure, the completion and well test required design of numerous new equipment to successfully perforate, fracpac and flow test the Tahiti #1 discovery well. Technologies that had to be developed for the Tahiti well test were:

- Subsea test tree system.
- Perforating firing head.
- Perforating guns and shock absorbers.
- Downhole isolation production valves.
- Smart well test production flow valve.
- Downhole electric 25,000 psi pressure gauges.
- Coil tubing string (2-in. OD rated to work at Tahiti well conditions).
- Design and qualification of production vacuum-insulated tubing (VIT).
- Design and qualification of production string.
- Design and qualification of perforating and fracpac completion string.

While many of these technologies were developed simultaneously, initial efforts to design and qualify the perforating and fracpac completion string started in September 2002. Several design considerations were established for the completion string. First, a 10 1/8 in.-by-9 7/8 in. protective liner was installed in

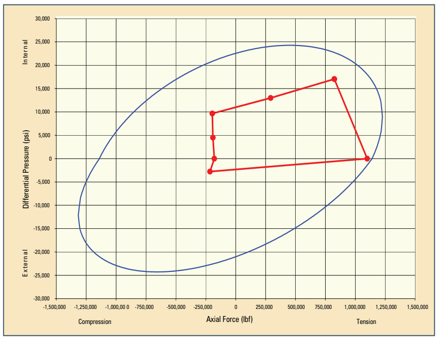


Figure 3: VME curve for 5 7/8-in. 0.500-in. wall S-135 tube encompasses all seven load points.

the well from 16,900 ft MD to 26,500 ft TD. The protective liner was tied back to the wellhead with a 10 ¾ in.-by-9 7/8 in. tieback string. All completion string configurations were required to be fishable within the 9 7/8-in. tieback, limiting the connection OD to 7 in.

Second, the depth, bottomhole pressure and overburden stress of the reservoir dictated elevated treating rates during the fracpac to establish an extensive fracture network in the formation. A large inside diameter (ID) completion string was required to provide the treating rate during fracturing operations. Initial hydraulic and frictional loss modeling indicated a 5 7/8-in. OD completion string with a connection no less than 4 ¼-in. ID was desired from top to bottom of the well.

Third, to achieve screenout during the fracpac, an estimated 29,000-psi absolute pressure internal to the completion string was required. The completion string and its connection were required to sustain these internal pressures and not leak, potentially jeopardizing the fracpac results.

Fourth, the tubing conveyed perforating assembly utilized a hydraulic firing head that was detonated with annulus pressure expected to be approximately 24,500 psi absolute. The completion string and its connection were required to sustain elevated external pressures of this magnitude and not collapse or leak.

Fifth, to enable multiple trips into the well for cleanout, displacement, perforating and fracture operations, the connection needed to withstand multiple make-up and breakout cycles while maintaining sealability at pressure. The completion string was required to make up to 20 trips into the well.

Finally, since the completion string would not be used to flow the well, it was not required to seal gas-tight. Rather, the connection required a high-performance metal-to-metal seal that possessed integrity against fluid leak.

Considering these requirements, a vertically integrated, comprehensive design and qualification program was commissioned for the completion string. The program consisted of the following:

1. Predict the actual loads applied to the completion string. Utilize safety factors to identify the load requirements for the completion string.

2. Design the completion string (tubular and connection) to meet the load requirements. Use predictive stress simulators such as Finite Element Analysis (FEA) to confirm the design.

3. Qualify, and physically test the completion string (connection) to actual predicted loads.

4. Correlate the physical test data back to the FEA data to gain confidence in the design.

LOAD REQUIREMENTS

The determination of loads and stresses applied to the completion string were crucial to its design. The completion string was modeled and a series of load cases were determined. The load cases consisted of:

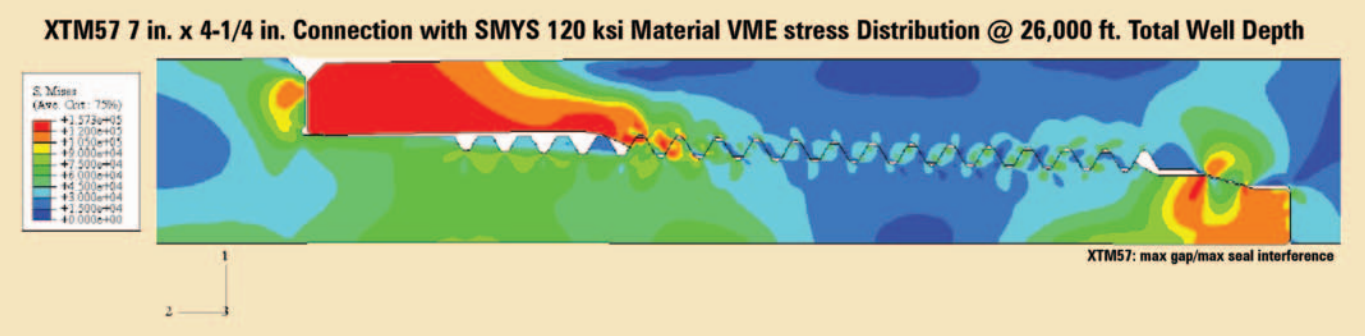


Figure 4: FEA output indicates box counterbore collapse of 120,000-psi XT-M57 connection at 26,500 ft TD for fracturing with 4,000-psi leak case (load point 7).

1. Initial condition (hook load). This load case was defined by the weight of the packer fluid used to land the tubing and the packer landing conditions.

2. Production at 15,000 BOPD. This load case was defined by the max possible production rate, the production flowstream characteristics and the flowing temperatures/pressures of the formation.

3. Fracture stimulation. This load case was defined by the max possible injection rate, the injection frac fluid/proppant characteristics and the pumping temperatures/pressures at the wellhead.

4. Fracture stimulation with leak. This load case was created to simulate a connection leak at the mud line during the fracpac. The load case considered the maximum additional 4,000 psi that could be transferred to the annulus.

5. Screenout during stimulation. This load case was based on the fracturing load conditions with plugged perforations. No pressure loss in the tubing would transfer the entire applied pumping pressure and frac fluid hydrostatic pressure to the bottom of the string.

6. Perforate the well. This load case would see applied external pressure at the surface to detonate the tubing conveyed perforation assembly. These load cases yielded calculated values along the depth of the completion string. The values generated were:

- Depth of calculation on the completion string.
- Axial load.
- Internal pressure.
- External pressure.
- Temperature.

From this data, a load curve was developed that illustrated the loads throughout the completion string for each of the four operational cases (Figure 1). Seven key

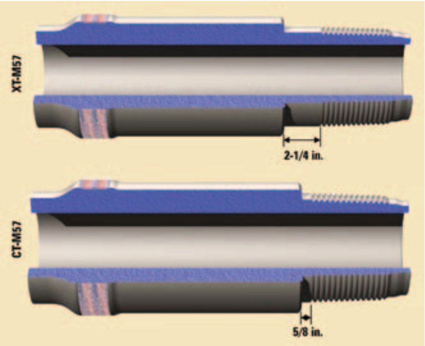


Figure 5: Differences between the CT-M57 and the XT-M57 connection are the shorter counterbore distance and initial clearance for the secondary shoulder (gap width) at 'hand-tight' make-up.

points from the load curve were identified:

1. Hook load: 1 million lbs of tension with an internal and external pressure of 0 psi.

2. Fracture stimulation at the surface: 750,000 lbs of tension with an internal pressure of 15,500 psi and an external pressure of 0 psi.

3. Fracture stimulation at 12,000 ft MD: 266,000 lbs tension with 21,102 psi internal pressure and 10,219 external pressure.

4. Screenout at the bottom: 177,700 lbs of compression with an internal pressure of 27,200 psi and an external pressure of 20,254 psi.

5. Fracture stimulation at the bottom: 173,200 lbs compression with 22,500 psi internal pressure and 20,254 psi external pressure.

6. Perforation at the bottom: 162,600 lbs of compression with an internal and external pressure of 19,254 psi.

7. Fracture stimulation at the bottom with 4,000-psi leak at the mud line: 118,700 lbs compression with 22,500 psi internal pressure and 23,254 psi external pressure.

Safety factors were applied to these seven points. For axial loads, a 1.1 safety factor was applied.

The pressure values were treated somewhat different. Rather than applying a 1.1 safety factor to both the internal and external pressure, the 1.1 safety factor was applied to the greater of the two pressures.

The lower pressure remained the same. This increased the magnitude of the differential pressure. For positions where the internal and external pressures were equivalent, a 1.1 safety factor was applied to both pressures. These seven points with safety factor applied were then plotted on the load curve and represent the service load envelope for the completion string (Figure 2).

Additional requirements not presented in Figure 2 were temperature and bending. Maximum bottomhole temperature was expected to be 200°F, 220°F with safety factor applied. Maximum anticipated bending from buckling and curvature in the string was 10°/100 ft, generating approximately 3°/100 ft across the connection.

TUBULAR EVALUATION

Defining the tubular size, weight and grade for the load requirements proved straightforward compared with the connection selection. The tube was required to meet the load requirements, accommodate a maximum connection OD of 7 in., a minimum connection ID of 4 ¼ in. and have a large tube ID to maximize hydraulic efficiency during the fracpac operation. API S-135 grade pipe was selected. 5 7/8-in. S-135 von Mises equivalent (VME) curves were then plotted for various wall thicknesses and positioned on the service load curve. Figure 3 illustrates the final size selected, 5 7/8-in. 0.500-in. wall S-135. It encompassed all seven load points while providing the largest ID possible for minimal fluid friction loss during the fracpac.

CONNECTION EVALUATION

Significant pressures along with multiple make-up and breakout requirements

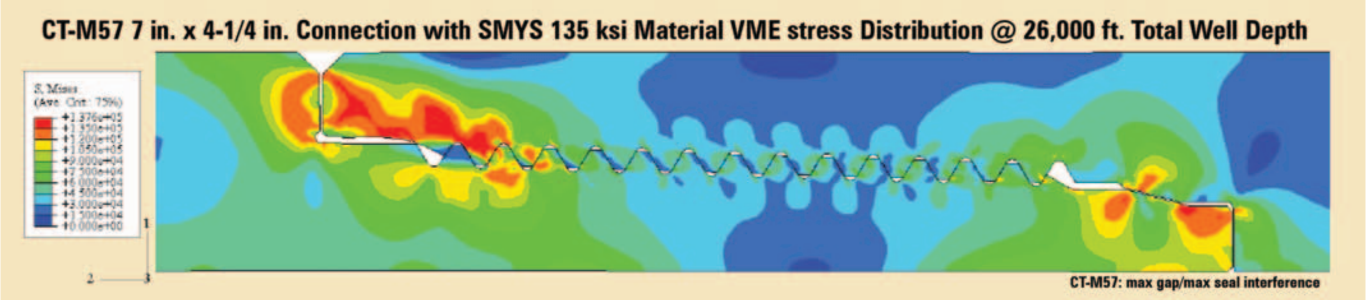


Figure 6: FEA output indicates structural integrity of CT-M57 connection at 26,500 ft TD for fracturing with 4,000-psi leak case (load point 7).

led the design team to first analyze the eXtreme Torque metal-to-metal seal connection (XT-M), specifically the XT-M57 connection, because of its standard 7 in.-by-4 ¼ in. configuration for 5 ⁷⁄₈-in. pipe. The XT-M connection is a rotary shouldered connection (RSC) with a radial metal-to-metal flank seal on the pin nose. The XTM connection combines the rugged configuration, durability and ease of handling and make-up of a RSC with the gas-tight pressure integrity of a premium tubing connection. XT-M is the first and only pressure-rated RSC. XT-M is gas-tight pressure rated to 15,000 psi internal pressure and 10,000 psi external pressure.

FEA of the XT-M57 Connection: A common approach when analyzing connections with FEA is to apply only differential pressure across the connection. This approach can be misleading, especially when internal and external pressures are high. The application of absolute internal and external pressure, even when equal in magnitude, generates both tangential and radial stress within the connection. This fundamental concept was the basis for the design team's use of absolute pressure FEA modeling throughout the development program.

The primary seal of the XT-M connection is the 15° flank seal on the pin nose. The external shoulder provides a secondary seal. The secondary shoulder internal to the connection acts as a torque stop and is not considered a seal. This permits the connection to be racked back on the pin nose during tripping operations without damaging the seal. Because the connection essentially has two seals, 15° flank seal on the pin nose and the external shoulder, for purposes of the connection analysis it was assumed that the pressure between the two seals after make-up of the connection is zero. This assumption does not include increased pressure resulting from trapped volumes of thread compound during make-up nor the effects of temperature to the constant volume of thread compound between the seals.

Additionally, if the internal secondary shoulder were to seal, though not designed to, it can also be assumed that the pressure between it and the 15° flank seal is also zero. This essential concept was applied to all double seal connections modeled during the test program, including the XT-M connection. This dictated a loading scenario of applying absolute external pressure on the OD of the connection, zero pressure in the threaded region, zero pressure between the flank seal and the secondary shoulder and absolute internal pressure within the inside of the connection.

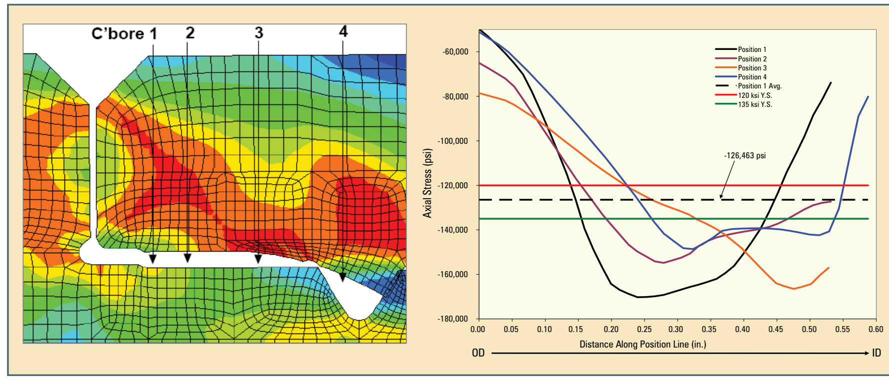


Figure 7: Stress analysis across CT-M57 box counterbore in 4 sections indicates maximum average axial stress to be 126,463 psi at TD = 26,500 ft for the fracturing with 4,000-psi leak case (load point 7).

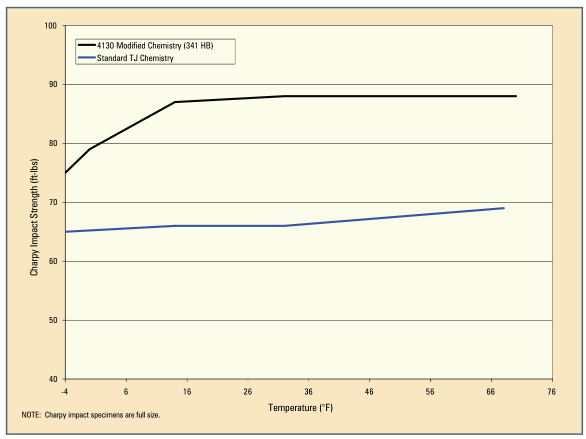


Figure 8: Charpy impact transition curves for 4130 modified and standard tool joint material manufactured to equivalent elevated toughness criterion. 4130 modified tool joint material heat-treated to upper end of yield strength/hardness range (152,000 psi/341 HB) shows improved toughness over the range of tested temperatures.

A 2-D axisymmetric model of the XT-M57 connection was generated using Abaqus V6.3-2 FEA software. Nonlinear stress-strain curve data for standard 120,000-psi tool joint material were input to the model to permit analysis of both elastic and plastic material behavior.

The results of the FEA revealed that the extended box counterbore lacked stability under the immense external pressure and compressive loads anticipated at the bottom of the well. The fracturing with 4,000-psi leak case (Load Point 7) presented compression due to make-up, 215,160 lbs additional string compression and 25,279 psi external pressure to the box counterbore. As shown in Figure 4, sectional stresses in the box counterbore significantly exceeded the material capabilities and counterbore collapse was predicted.

In an attempt to avoid design of a new connection, a dual OD tapered string was reviewed for feasibility. Smaller connection sizes including XT-M50, XT-M43 and XT-M34 were analyzed. Only the smaller size XT-M connections suggested feasibility, explaining reports of other oil companies using up to four OD tapered strings for completion operations at similar depth. However, review of the pressures for the treating rates needed during the fracpac indicated the tapered string presented too much frictional loss. The desired treating rates could not be achievable. A 7 in.-by-4 ¼ in. connection was required from top to bottom. A new connection, a modified XT-M57 connection had to be developed.

DEVELOPMENT

To provide additional rigidity and structural stability to the box counterbore of the XT-M57 connection, the counterbore length was shortened from 2 ¼ in. to ⁵⁄₈ in. The modified connection was named the CT-M connection, specifically CT-M57.

Figure 5 shows the differences between the XT-M57 and the CT-M57 connection. The CT-M57 connection then underwent a series of design iterations. Adjusting the box counterbore length created an imbalance of forces acting on the internal and external shoulders. The initial clearance (gap width) between the pin nose and the box internal shoulder when the connection is made-up "hand tight" (describing the position when the external shoulder is just touching) had to be adjusted.

Gap widths used for the XTM57 connection were not applicable to the CT-M57 connection and did not balance the stresses between the box counterbore and pin nose. Taking into account manufacturing tolerances for the pin length and box depth, the proper gap width for the CT-M57 secondary shoulder was determined through a series of FEA runs.

The gap width selected for the CT-M57 connection balanced the stresses in the box counterbore and pin nose and resulted in a nominal gap width less than that of XT-M57. The metal-to-metal seal design, seal interference tolerance, of the CT-M57 connection remained the same.

The CT-M57 connection would have similar gas-tight sealing capability. Like the XT-M57 connection, the CT-M57 connection has manufacturing tolerances governing the interference of the 15° flank seal and the gap width of the secondary shoulder. Manufacturing tolerances applied to these two independent dimensions yields four possible combinations of connection dimensions.

• Maximum gap / maximum seal interference.

• Maximum gap / minimum seal interference.

• Minimum gap / maximum seal interference.

• Minimum gap / minimum seal interference.

Each of these four configurations was analyzed with FEA against the anticipated Tahiti loads. The worst case configuration for the box counterbore proved to be the max/max configuration. Although there was tremendous improvement over the XT-M57 connection, the CT-M57 connection still showed sectional stress values in the box counterbore that exceeded the 120,000 psi material yield strength for Load Point 7 at the bottom of the well. A decision was made to investigate the feasibility of high-strength tool joint material, 135,000 psi minimum yield strength, for the CT-M57 connection.

FEA OF CT-M57

Nonlinear stress-strain curves for previously manufactured 135,000-psi material were obtained and input to the FEA software. Again, this enabled analysis of both elastic and plastic material behavior. The max/max CT-M57 configuration was again analyzed with FEA to the loads provided in Load Point 7. Shown in Figure 6, the FEA results suggested substantial improvement.

First, the connection exhibited great structural stability. Second, the box counterbore had reduced stress compared with the XT-M57. Localized counterbore stress values remained elevated, but bulk cross sectional stress appeared within desired parameters. The 135,000-psi CT-M57 connection appeared to meet the most stringent load requirements of Tahiti.

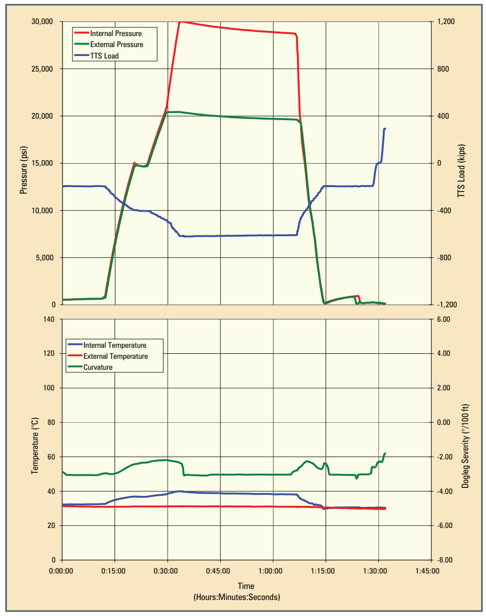


Figure 9: Load point 4 during Cycle #2 testing at ambient temperature. CT-M57 sample connection #1 maintains seal over 30+ minutes with internal oil pressure up to 29,020 psi.

To further analyze the box counterbore, sectional axial stress within the counterbore was studied. Like the XT-M57 connection, the box counterbore of the CT-M57 connection was the most stressed area. Figure 7 presents the analysis used. The box counterbore was probed at four distances from the external shoulder. For each position, the axial stress in the counterbore section was plotted. Position One nearest the external shoulder showed the highest axial stress profile. The local peak axial stress exceeded 135,000 psi, but the average axial stress across position one was 126,463 psi. Position Four furthest the external shoulder indicated less actual and average stress across its profile.

For all four locations, a portion of the axial stress profile exceeded 135,000 psi, but the VME stress was much less than 135,000 psi. This result indicated that there was potential for localized stressed conditions, but bulk cross section yielding was unlikely to occur. The counterbore was stable and not predicted to collapse.

FE analyses were performed on the remaining three CT-M57 configurations. The 135,000-psi CT-M57 proved to meet the loads and was a solution to the challenging Tahiti environment.

TOOL JOINT MATERIAL

API tool joints have a minimum yield strength requirement of 120,000 psi. The CT-M57 connection for the Tahiti project required 135,000 psi minimum yield strength to ensure structural integrity of the box counterbore under compression and external pressure. A development program to test the feasibility of an industry-first, commercially available 135,000 psi tool joint material was commissioned.

In addition to the high-strength requirement, other desirable mechanical property requirements were identified:

• Maximum yield strength of 150,000.

• Minimum tensile strength of 145,000 psi.

• Minimum elongation of 13%.

• Minimum hardness of 302 HB.

• Maximum mid-wall hardness of 41 HRC.

• Maximum hardness variation of 6 HRC.

• Minimum Charpy impact strength of 31 ft-lbs average at -4°F using full size specimens.

Of particular importance to the development program was the material's fracture toughness if manufactured on the upper end of the strength / hardness range. The development program needed to prove that 135,000-psi CT-M57 connections manufactured in the upper strength / hardness range possessed equivalent or better fracture toughness compared with standard tool joint material manufactured to elevated Charpy impact requirements.

Special 4130 modified steel was selected that consisted of high alloying elements and low nonmetallic impurity elements such as phosphorous and sulfur. The chemistry was selected to provide uniform hardness and through wall martensitic transformation during the special heat treat and quench process.

A quenching medium was selected to quickly remove heat from the tool joint material and assure martensite transformation.

Multiple material samples were heat treated and tested until the desired tempering temperature and time were identified. Special samples were manufactured that were on the upper end of the strength / hardness range (152,000 psi / 341 HB).

Confirmation of the material's fracture toughness was obtained by performing Charpy impact strength tests over a range of temperatures from -4°F to room temperature. Illustrated in Figure 8, the Charpy transition curves showed that the 4130 modified steel possessed higher fracture toughness across the entire temperature range compared with tool joint forgings manufactured to standard yield strength and equivalent, elevated toughness criterion. The 4130 modified steel ranged from 75 ft-lbs at -4°F to 88 ft-lbs at 70°F, a 15% to 28% improvement over the standard material. This performance improvement was obtained despite the 4130 modified material being manufactured on the extreme upper end of the strength / hardness range.

Further confirmation of the material's fracture toughness was acquired through a second fracture mechanics test. Crack Tip Opening Displacement (CTOD) testing was performed on the 4130 modified material and compared with standard tool joint materials. CTOD is a measure of the material's ability to resist crack propagation. CTOD values can be used as a measure of fracture toughness for metallic materials and are especially appropriate to materials that exhibit significant plasticity prior to failure.

Table 1 presents the results of the CTOD testing, showing the 4130 modified material produced 19% improved fracture toughness compared with standard tool joint material and 73% improved compared with standard tool joint material manufactured to equivalent yield strength values.

The testing confirmed when using special chemistry and heat treatment parameters, a high-strength / high-toughness tool joint could be manufactured to meet the Tahiti load requirements. Several full size CT-M57 connection samples were then manufactured to the lower end of the strength range to be used for the connection testing program.

Material	Yield Strength (psi)	CTOD Result (in)
Standard TJ	125,000	0.0064
Standard TJ	152,000	0.0044
4130 Mod. TJ	152,000	0.0076

Table 1: Crack tip opening displacement (CTOD) tests show 4130 modified material heat-treated to the upper end of the yield strength range is 19% improved compared with standard tool joint material at 125,000 psi yield strength and 73% improved at equivalent yield strength values.

CONNECTION TESTING

Physically testing the CT-M57 connection to Tahiti loads proved a major challenge. It is common to test rotary-shouldered and premium connections using differential pressure across the connection rather than simultaneously applied internal and external absolute pressures. Testing differential pressure is effective at determining leak characteristics of the connection but does not produce the actual stress levels seen by the connection in the field. Because the CT-M57 connection needed to not only seal fluid pressure but also withstand elevated axial, hoop and radial stress, a more representative physical testing program was desired to qualify the CT-M57 connection.

TESTING PROGRAM

The approach used during FEA assumed absolute pressures along the OD and ID of the connection with zero absolute pressure in the threaded region. Like the FEA approach, the decision was made to physically test the CT-M57 connection to absolute pressures on the inside and outside of the connection. The testing program required simultaneously applied internal and external pressures up to 29,000 psi, with tensile loads up to 1,100 kips, compressive loads up to 215 kips, bending loads equivalent to 3°/100 ft dog leg severity (DLS) and temperature up to 220°F.

Believed to be the industry-first connection qualification test to simultaneously apply internal and external absolute pressure to a rotary-shoulder connection, the test requirements exceeded the capabilities of most test labs. Canada's **C-FER Technologies** was selected to execute the test based on the capabilities of its Tubular Testing System (TTS). It is a closed-loop, servo-hydraulic loading system that provides full-scale structural and reliability testing. The system can accommodate specimen sizes up to 49.2 ft long and up to 5 ft in diameter.

TTS can apply static tensile or compressive loads up to 34 million lbs, temperatures between - 40°F and 752°F, bending or lateral loads and most importantly, monitor for leaks with simultaneously applied internal and external pressures.

A test program was identified to include six of the seven load points. Load Point 6 was not included because it had equivalent internal and external pressure and successful demonstration at Load Points 5 and 7 would satisfy the requirements of Load Point 6. The test program methodology included cycling around the service load point curve in one direction at elevated temperature, a second cycle in the opposite direction at ambient temperature and a third cycle in the original direction at elevated temperature. Each sample connection underwent these three cycles of tests. Table 2 presents the load steps for Cycle #2 at ambient temperature. Not presented in the table is the 3°/100 ft DLS that was applied to the connection in all three cycles.

Three of the four connection combinations were required for testing.

• Sample 1 – maximum gap / maximum seal interference (worst case configuration for box counterbore stress).

• Sample 2 – minimum gap / maximum seal interference (worst case configuration for pin nose stress).

• Sample 3 – minimum gap / minimum seal interference (worst case configuration for sealability of the connection).

The maximum gap / minimum seal interference combination was not tested because FEA indicated the minimum gap / maximum seal interference combination produced greater stress levels in the pin nose.

A total of six CT-M57 connections (three above configurations and three backup) were machined from material manufactured on the lower end of the 135,000-psi strength range. The mechanical properties 1 in. below the 7 ½-in. diameter bar were:

• Yield Strength – 139,500 psi

• Tensile Strength – 151,400 psi

• Elongation – 19.8%

• Charpy Impact Strength – 84 ft-lbs (average of three full-size tests taken at -4°F)

• Hardness – 341 HB (NOTE: taken on the OD of the 7 ½ in. bar)

All connections were made up to maximum make-up torque (51,600 ft-lbs) and monitored using torque turn equipment. This was done 23 times to simulate the manufacturing break-in procedure and expected make and break cycles in

Load Step	Service Load Point	Axial Load (kips)	Internal Pressure (psi)	External Pressure (psi)	Hold time (min)
1		-215.2	0	0	10
2	7	-215.3	22,500	25,279	30
3		-215.2	0	0	10
4		-190.5	0	0	10
5	5	-190.5	24,750	20,254	30
6		-190.5	0	0	10
7		-195.5	0	0	10
8	4	-195.5	29,920	20,250	30
9		-195.5	0	0	10
10		293	0	0	10
11	3	293	23,212	10,220	30
12		293	0	0	10
13		825	0	0	10
14	2	825	17,050	0	180
15		825	0	0	10
16	1	1100	0	0	10

Table 2: Cycle #2 applied to CT-M57 connection at ambient temperature during the physical test program. Cycles #1 and #3 were equivalent in values, but load steps were in the opposite direction and included 220˚F. All three cycles included 3˚/100 ft DLS applied to the connection throughout the test.

the field. Each connection was visually examined. Bypass holes were drilled in the small diameter of the pin nose and the box counterbore of Sample 3 and its backup. This was done to avoid any sealing effects of the primary and secondary shoulders and test the 15° metal-to-metal primary seal during the sealability test. The connections were then made-up to their minimum make-up torque (43,000 ft-lbs) and sent to C-FER.

TEST EXECUTION, RESULTS

At C-FER, four strain gauges were positioned on the ID of each pin connection spaced 90° apart, and four strain gauges were installed on OD of each box connection spaced 90° apart in the counterbore region. All samples were then made up to their test make-up torque. Structural test Samples 1 and 2 were made up to maximum make-up torque (51,600 ft-lbs), and the sealability sample with the drilled bypass holes was made up to minimum make-up torque (43,000 ft-lbs).

Over approximately two months, the three sample connections were loaded into the TTS and underwent the three cycle test program. Strain gauge data was monitored and recorded. Fluid leak detection was confirmed by monitoring the oil pressure within the ID of the connection and within the external chamber surrounding the connection. Unlike premium connection gas testing where leak detection is confirmed by volume measurement, monitoring pressure changes in the inside and outside of the CT-M57 connection proved definitive. The test apparatus was constructed such that no leak path was present from the interior to the exterior pressure chambers other than across the CT-M57 connection.

Figure 9 presents data obtained while testing the structural Sample 1 during Load Point 4 of Cycle #2 testing at ambient temperature. As shown in the figure, the CT-M57 connection successfully sealed pressure over a 30-minute hold time with no leaks. A drop in both internal and external pressure is noted during the hold time. This was attributed to a drop in temperature over the hold period after the oil absorbed frictional heat when initially injected into the pressure chambers. Each sample connection underwent the test program, and all connections passed without incident. No connection leak was observed for any CT-M57 connection.

CORRELATION TO FEA

To ensure FEA decisions made during the connection development program were sound and the results accurate, the strain gauge data obtained during the physical testing was compared with the strain predictions made by FEA. The physical parameter selected for comparison was axial strain at the box counterbore OD and pin nose ID. Strain comparisons for the load cases were performed only for Cycle #2 of the testing program, the ambient temperature cycle. This was done because the FEA was based on stress-strain curves obtained on the 135,000-psi material at ambient temperature. To simulate the potential of cumulative plastic strain during the physical test, the FEA model was loaded according to the actual Cycle #2 test load sequence.

Net strain change after make-up from each of the four strain gauges on the pin and box connection was plotted alongside their average. FEA predicted net strain in the box counterbore and pin nose was also plotted to compare with test data. Figure 10 shows the results for the structural Sample 2 throughout Cycle #2 at ambient temperature.

Overall, FEA prediction correlated reasonably well with the test data, especially in predicting the overall trend. The maximum difference in net strain change was approximately 353 me associated with Load Point 7, the worst case condition for the box counterbore. FEA strain prediction was more conservative in most of the load cases. For Load Point 7 and other compressive load cases with external pressure, FEA predicted higher compressive strain than physical test results.

Since the physical test data did not indicate overall strain levels higher than FEA predictions and no failures or leaks were noted during the test program, the 135,000 psi CT-M57 connection was commissioned for use on the Tahiti project.

MANUFACTURE

Manufacturing of the completion string commenced during the fourth quarter of 2003. Of particular importance was the manufacture of the high-strength tool joint material. Considering average stress levels in the box counterbore section were predicted to be approximately 126,463 psi at the bottom of the string, it was critical to obtain the desired strength, hardness and toughness range for the tool joint material. Through improved chemistry, advanced heat treatment and process controls during manufacturing, the desired tool joint material properties were maintained.

Table 3 presents the mechanical property results obtained during manufacture of the 135,000-psi tool joint material. Strength values were achieved while maintaining toughness properties (approximately 93 ft-lbs average), well above the 31 ft-lb average minimum allowed. Consistent hardness properties were maintained across the wall thickness of the material with only approximately 1 HRC reduction from the OD to the ID.

The 5 $^{7}/_{8}$-in. CT-M57 string completed manufacturing during the first quarter of 2004.

WELL TEST

The Tahiti #1 well was completed and flow tested from May 2004 to August 2004. The CT-M57 string was first used to clean out the well, displace the drilling mud to completion fluid and then used to perforate and fracture the reservoir. The weight of the fracture fluid was slightly heavier than designed, and treating pressures were kept slightly lower as a result. The large ID 5 $^{7}/_{8}$-in. CT-M57 completion string delivered efficient hydraulics and enabled elevated treating rates during the fracpac. Screenout was achieved during fracturing, and all indications suggested the completion string experienced loads approaching the levels anticipated during the design process. Throughout all field operations, no issues were noted with the string. The string experienced no leaks and performed without incident.

Following completion of the well test in September 2004, ChevronTexaco estimated it could produce as much as 30,000 BOPD from the Tahiti prospect. Analysis of the rate and pressure data collected during the well test indicated the well's capability exceeded the pre-test expectation of 25,000 BOPD.

Engineering work on the Tahiti project's subsea systems and floating production facility is under way. Over the next several years, the Tahiti field will be developed from two subsea drill centers located near the two Tahiti appraisal wells.

CONCLUSIONS

A new connection was successfully designed, analyzed, tested and deployed to make it possible to safely perform an ultra-high pressure fracpac under severe conditions. The connection combines the ruggedness and high torsional strength of a rotary-shoulder connection with the pressure integrity of a premium casing or tubing connection. The connection and accompanying completion string enabled ChevronTexaco to exploit one of the most significant oil discoveries in the history of the deepwater Gulf of Mexico.

The design team identified critical anticipated service loads, determined the optimum connection configuration and material properties necessary to resist the loads and thoroughly analyzed and tested the new connection to insure it provided the solution to this challenging fracture operation. The design solution featured ultra-high strength tool joint material with excellent fracture toughness and impact properties.

For acknowledgements and references, please go online to www.drillingcontractor.org.

The authors thank Darryl Williams of Shell, Paul Hebert, Kevin Kohler, Mike Koster, Jim Skogsberg, Kevin Turner, Jiang Wu and Kevin Corbin of ChevronTexaco for their contributions during the design, testing, manufacture and implementation of the Tahiti CT-M57 completion string. The authors thank Frank Carlin, Tom Moore and Mike Dibbley of Grant Prideco for their contributions in the development of the highstrength tool joint material. The authors thank Jim Breihan, Wei Tang, Ricky Lawrence and Steve Langford of Grant Prideco for their contributions in the design, FEA and testing of the CT-M57 connection. The authors extend their appreciation to C-FER Technologies for their participation in the CT-M57 testing program. The authors thank Greg Elliot of Workstrings, LLC and Ed Mazurek of Mitsui for their purchase of the CT-M57 completion string. The authors also express their gratitude to themanagement of ChevronTexaco and Grant Prideco for their support and encouragement in publishing this paper.

References

1. Boas, Nancy, "Subterranean Seers," CVX (Third Quarter 2003) 14.

2. "ChevronTexaco Makes Discovery at "Tahiti" Prospect in Deep Water Gulf of Mexico," ChevronTexaco Press Release, April 1, 2002.

3. "ChevronTexaco Announces Successful Results from Tahiti Appraisal Wells in Deepwater Gulf of Mexico," ChevronTexaco Press Release, April 22, 2003.

4. Shirley, Kathy, "GOM Yields Exotic Tahiti Discover," Explorer, July 2003.

5. Christen, B.L., Jellison, M.J., Tinker, S.J., Walker, T., Broussard, S., "Technological Advances of Completion Pipe Design," IADC/SPE 87200 presented at the 2004 IADC/SPE Drilling Conference.

6. C-FER Technologies Tubular Testing System website. (n.d.). Retrieved October 30, 2004, from http://www.cfertech.com/CORE/Facilities/tts.html

7. ISO 13679:2002 Petroleum and natural gas industries – Procedures for testing casing and tubing connections, first edition, International Standards Organization, December 2002.

8. Tang, Wei, "Analysis Report on Correlation of Physical Test and FEA Simulation," May 17, 2004.

9. "Tahiti well test exceeds expectation," ODS-Petrodata, Inc. Gulf of Mexico Newsletter, Edition Number 041025, October 22, 2004.

This article is based on a presentation at the 2007 DEA Workshop, 19-20 June 2007, Galveston, Texas.

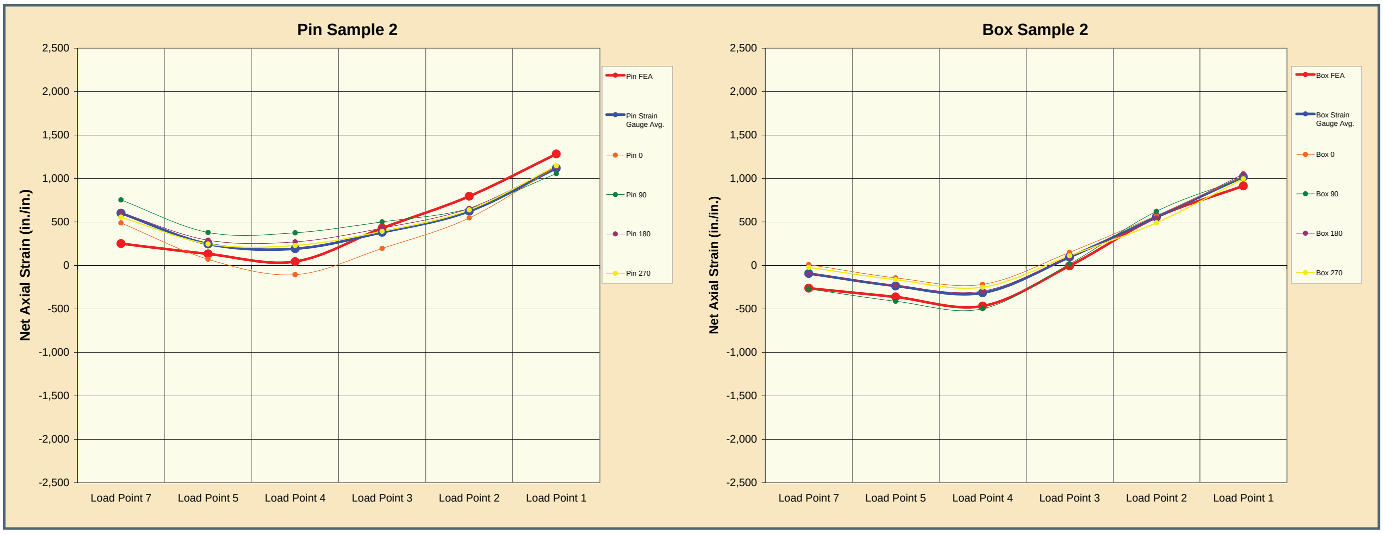


Figure 10: Test strain gauge data for Sample 2 pin (left) and box (right) vs. FEA-predicted data. Overall, very good correlation of FEA to test data was found. FEA appeared slightly more conservative than test results and showed better correlation on box data than on pin data, attributed to the pin strain gauge being positioned in a fast-strain transition zone.