Abstract

Because of large potential reserves and increased global demand for oil and gas, deepwater exploration and development has become a key area for most E&P companies. Deepwater development challenges include higher hydrostatic and reservoir pressures, strong ocean currents, and ever-changing weather conditions. Therefore, a clear understanding of the requirements of this challenging environment is imperative to maximize safety and efficiently complete and commission wells for optimal reliability and reservoir recovery. Of particular concern are the completion activities on deepwater wells from dynamically positioned (DP) vessels. A key challenge is the reliable installation of subsea and completion equipment while maintaining well control. DP vessels require dependable subsea landing string technology capable of fast-acting operation that is independent of water depth. In an emergency, the system must perform a fully sequenced emergency shutdown and disconnect in as little as 15 seconds.

This study includes a review of the subsea landing string technology already in use in deepwater fields and the development of new technologies designed and qualified to meet the particular challenges associated with the Petrobras Cascade and Chinook fields in the Gulf of Mexico. These technologies included the use of a high-pressure-rated subsea test tree and an electrohydraulic operating system, coiled-tubing cutter module (CTCM), and project-specific equipment (e.g., slick joints, latch mandrels, and spacers). Special emphasis was placed on the validation testing performed on the hardware to assure functionality and reliable operations at project-specific conditions, including working at extreme hydrostatic pressures due to completion fluid weight and water depth. These tests included hydrostatic pressure testing at a simulated riser environment with respect to pressure and temperature (7,500-psi hydrostatic pressure, 15,000-psi bore pressure, 275 degF), validation of ball valve cutting capabilities for specified coiled tubing, and qualification of new hardware.

Engineering efforts, planning, and preparation resulted in the completion of Cascade#4 and Chinook#4 without safety or environmental incidents and within the planned cost and schedule.

1. Introduction and Challenges

Cascade and Chinook are Petrobras’s first lower-tertiary developments in the US Gulf of Mexico. Both fields are in the Walker Ridge area of the outer continental shelf (Figure 1). The fields are approximately 160 miles (257 kilometers) south of the Louisiana coast in 8,850 ft [2,700 m] of water.
The Cascade and Chinook discoveries defined a new hydrocarbon trend in Gulf of Mexico ultradeep water. The hydrocarbon-bearing sandstones are similar to the Wilcox Group (Eocene-Paleocene) level, which is a prolific producing sediment onshore USA. Both fields will be tied back to the first floating production, storage, and offloading vessel (FPSO) to be deployed in the US Gulf of Mexico.

Petrobras will develop the field with a disconnectable submerged turret production buoy including fluid swivel and appurtenant mooring system. This unusual design will enable the FPSO to disconnect from its moorings and seek sheltered waters in a hurricane situation with minimum disruption to operations. The FPSO will be on location close to Cascade field in the third quarter of 2010, and production startup is slated for the second half of 2010. The first phase of the project consists of one well completion in the Chinook field plus two wells in the Cascade field. Future phases will be planned based on results from the first phase.

Cascade- and Chinook-field development well challenges included:
- construction in limited operational timeframes due to weather, risks, and costs associated with operation in ultradeep waters
- vessel’s DP position keeping
- working at extreme hydrostatic pressures due to completion fluid weight and water depth
- planning for several simultaneously deployed DP vessels depending on availability
- contingencies such as coiled-tubing intervention planning.

2. Project Requirements and Scope

The subsea design consists of horizontal trees with the upper completions deployed with a subsea landing string. Petrobras contracted Schlumberger to install upper well completions using its 15,000-psi rated subsea test tree (SSTT) augmented by the high-pressure rated subsea electrohydraulic (EH) operating system. The system is used to install the completion, maintain well control, and provide quick disconnect from the landing string during flowback and cleanup operations. Reasons for initiating SSTT valve closure and landing string disconnect include adverse weather conditions, rig equipment failure, and DP vessel drift-off.

Petrobras’s planned field development required a full subsea landing string including the provision of a SSTT, an electrohydraulic operating system, spacer subs, slick joint, lubricator valve, flow head, and crossovers. Below are some of the project requirements and the basis of design for the subsea landing string:

- Working temperature range: 40 degF to 270 degF
- Minimum working differential: 12,500 psi
- Maximum tensile load requirement: 400,000 lb at working pressure
- Water depth: 8,325 ft to 8,850 ft
- Hydrostatic pressures of 7,500 psi at the wellhead
- System drift: 5 3/8 in
- Cutting requirements: coiled tubing 2-in OD x 0.203 WT, wireline 0.4375 in, slickline 0.108 in
- Completion fluid: ZnBr
- Drilling units: West Sirius, Ocean Endeavor, and Discoverer Deep Seas

To ensure project risks were identified as early as possible in the process and mitigated at the appropriate time, a dedicated team for cohesion and thorough execution of necessary tasks was required. A full-time project manager (PM)
and engineering team were assigned to the project. Team discussions resulted in technical proposals to develop project-specific hardware or project-specific testing protocols/analysis to mitigate risk. Some examples included

- hazard analysis and risk-control review of dangers associated with high mudline pressures and subsequent selection of viable high-pressure equipment
- reviewing requirements for handling potential riser hydrostatic pressures of up to 7,500 psi since this high pressure exceeded existing qualification levels; therefore, hydrostatic-pressure qualification of subsea test tree and/or project specific hardware at simulated hydrostatic pressure was performed
- design of project-specific spacer subs, latch mandrel and ported slick joint to work in three different BOP stacks—for *West Sirius*, *Ocean Endeavor*, and *Deep Seas* rigs; this has given Petrobras the necessary flexibility in rig selection for completion installation
- Development of high-pressure rated large-bore coiled-tubing cutter module
- Performance testing of subsea test tree ball valve as a means to cut large-diameter coiled tubing as a contingency solution to large-bore coiled-tubing cutter module.

The following sections of this paper will focus on the new technology and the specific product qualifications and validation programs developed for the Cascade/Chinook project.

3. Electrohydraulic (EH) Operating System

The subsea landing string operating system requirements are driven by a combination of factors, including vessel type and completion complexity. Specific operating envelopes must be maintained with appropriate timings for well isolation and disconnect in the event of an emergency situation with an anchored or DP vessel. Operations performed from an anchored vessel can allow several minutes to perform a full emergency shutdown, including closure of the BOP rams and disconnect of the lower marine riser package. The equivalent time is reduced to seconds when operations are performed from a dynamically positioned vessel. Direct hydraulic operating systems meet the requirements for anchored vessels, although actual operating times are a function of umbilical length. DP vessels introduce the need for electrohydraulic operating systems for fast-acting well control.

The Cascade and Chinook completions were deployed with the Schlumberger new generation EH operating system. This new system features interchangeable mandrels and pressure-balanced accumulators. These allow both subsea control and accumulator modules to be combined in a single shorter assembly while providing the tensile strength, pressure rating, and hydraulic output needed for the ultra deep water and high hydrostatic conditions expected during the project.

With the new EH operating system, a fully sequenced emergency shutdown and disconnect of the landing string can be achieved in less than 15 seconds. This time can be adjusted and set according to the specific operating envelope requirements of the project. The electrohydraulic operating system also incorporates the capability to provide real-time telemetry feedback for verification of downhole and subsea equipment integrity and functionality during installation of more complex completion configurations.

The system also uses an innovative form of direct electrohydraulic control that reduces the number of hydraulic lines, thereby making possible the use of a single, small-diameter umbilical which reduces topside size and weight, eases handling, and improves deployment efficiency.

3.1 EH Operating System Validation Testing

As with any new product, component level and assembly level qualification is critical in order to assess and insure correct operation. Schlumberger has a comprehensive product development process to insure all checks and balances are incorporated into the product design and qualification. Prior to Cascade and Chinook, much of the subsea hardware was qualified to 5,000-psi hydrostatic pressure. Since Cascade and Chinook are operating near 7,500-psi hydrostatic pressure, it was recognized that certain parts of the system (including the new electrohydraulic operating system) require requalification at a higher hydrostatic pressure in order to validate performance.

Hydrostatic pressure qualification of the new electrohydraulic operating system was performed. Testing of subsea hardware was conducted with the equipment within a hydrostatic chamber simulating the riser environment with respect to pressure and temperature (Figure 2).
The system was function and pressure tested at ambient temperature. The system was cooled down and then soaked for 24 hours at low temperature to expose the system’s parts and seals to minimum operating temperature. The temperature was raised to 275 degF and then soaked for 48 hours at this temperature to expose the system parts and seals to maximum operating temperature. A second low-temperature qualification cycle was completed to simulate cool down of the string after well flow back. At each temperature cycle and at maximum operating pressures (bore, hydrostatic), the system was function tested as per factory acceptance test protocol. Qualification testing was successfully completed.

4. Coiled-Tubing Cutter Module (CTCM)

4.1 Coiled-Tubing Cutter Module (CTCM) Development

To meet the project requirements for cutting high-strength coiled tubing while maintaining the desired system drift, a new designed coiled-tubing cutter module was required. The benefit of developing the CTCM with the sole purpose of severing the coiled-tubing string upon command is that now the subsea test tree ball valve can be used only to seal and is no longer required to perform the dual function of cutting and sealing. This dual function role for the ball valve may impede the ability of the ball to seal after cutting the coiled tubing and thus reduces the effectiveness of this barrier element. So, it is felt that separation of these roles can reduce system risk when coiled-tubing intervention is a likely possibility for the project.

The existing 15,000-psi rated large bore coiled-tubing cutter module was designed with an ID of 5.12 inches, so a redesign of the cutter module to meet the larger bore requirements for Cascade and Chinook was required. At the same time the bore size of the cutter module was increased, Petrobras required two successful cuts of coiled tubing to validate the robustness of the module and the cutting blades. Refer to Table 1 for specifications of the new CTCM.

Table 1. CTCM Specifications

<table>
<thead>
<tr>
<th>Specification</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum OD (in)</td>
<td>18.56</td>
</tr>
<tr>
<td>Minimum ID (in)</td>
<td>5.50</td>
</tr>
<tr>
<td>Minimum inner drift diameter (in)</td>
<td>5.375</td>
</tr>
<tr>
<td>Maximum ID working pressure (psi)</td>
<td>15,000</td>
</tr>
<tr>
<td>Maximum ID test pressure (psi)</td>
<td>22,500</td>
</tr>
<tr>
<td>Maximum operating temperature (DegF)</td>
<td>350</td>
</tr>
<tr>
<td>Minimum operating temperature (DegF)</td>
<td>-32</td>
</tr>
<tr>
<td>Maximum torque (ft-lb)</td>
<td>40,000</td>
</tr>
<tr>
<td>Maximum tensile load at 0 psi (lbs)</td>
<td>1,200,000</td>
</tr>
<tr>
<td>Maximum tensile load at 15,000 psi (lbs)</td>
<td>500,000</td>
</tr>
</tbody>
</table>
The cutter module (Figure 3) is operated from two hydraulic supply ports through the main housing of the SSTT and is integrated with the EH operating system. When in hole, wellbore pressure will maintain the cutter pistons in the retracted position, thus allowing coiled-tubing/wireline tool passage.

Figure 3. CT cutter module.

4.2 Coiled-Tubing Cutter Module (CTCM) Qualification Testing

The qualification program included cutting testing at working pressure conditions (15,000-psi bore pressure and 7,500-psi hydrostatic pressure) at various test temperatures (ambient, low, and high) with a minimum of 2 successful cuts performed by the same blades at each test stage. This qualification requirement was recommended by Petrobras based on guidance derived from API RP16ST, which requires the surface CT BOP shear rams to make two successful cuts of coiled tubing with the same set of blades successfully. Refer to Figure 4 for the full qualification temperature profile.

Figure 4. CTCM qualification test temperature cycle.

During the low-temperature qualification test, the system was cooled down and then soaked for 18 hours at low temperature to expose the system parts and seals to minimum operating temperature. During the high-temperature qualification test, the temperature was raised to 275degF and then soaked for 48 hours at this temperature to expose the system parts and seals to maximum operating temperature. A second low-temperature qualification cycle was completed to simulate cool down of the string after well flow back. As mentioned earlier, at each temperature cycle, maximum operating pressures (bore, hydrostatic) were applied and two test cuts were successfully completed (Refer to figure 5).
At completion of the qualification process the coiled-tubing cutter module was removed and fully inspected for excess wear, along with performing a full nondestructive examination of the cutting blades themselves. Once the coiled-tubing cutter module passed all requisite testing, it was completely redressed, pressure tested, and mobilized to the field location.

4.3 Cutting Capabilities Validation Testing on SSTT Ball Valve

Due to the tight project schedule, use of the SSTT ball valve was considered as a contingency solution to cut large-diameter coiled tubing should the new coiled-tubing cutter module not been available in time for the Cascade and Chinook wells.

The Cascade/Chinook project selected a tapered (multithickness) coiled-tubing string. To evaluate the cutting performance and sealing capabilities of the ball valve after cuts with this customized coiled tubing, validation testing was performed.

Based upon input from Petrobras experts, coiled-tubing cut test protocols were developed based on anticipated environmental conditions of coiled tubing tension profiles, which were based upon the customized tapered coiled-tubing string used for these wells and the density of the completion fluids. Using this information, a predicted tensile load was applied to each coiled tubing wall thickness for cut testing to simulate a worst-case scenario in the well. Refer to Table 2 for the coiled-tubing testing basis of design.

The benefit of this approach is that the combination of tension to the coiled tubing while cutting better simulates subsea real-world conditions and gives a more exact understanding of the size and weight of coiled tubing that the device under test can cut. The element of stretch is important, as this provides the spring to the uphole portion of the coiled tubing, which will clear the upper valves in the SSTT. This length should be compared against the subsea stack-up drawings for clearances.

<table>
<thead>
<tr>
<th>Segment wall thickness (in)</th>
<th>Workstring depth at injector (ft)</th>
<th>Workstring depth, SSTT ball valve (ft)</th>
<th>Net weight* (lbm)</th>
<th>Axial stresses (psi)</th>
<th>Stretch above SSTT ball valve (feet)</th>
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</thead>
<tbody>
<tr>
<td>0.145</td>
<td>8,001</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>n/a</td>
</tr>
<tr>
<td>0.156</td>
<td>25,101</td>
<td>17,101</td>
<td>38,281</td>
<td>44,458</td>
<td>7.18</td>
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<tr>
<td>0.175</td>
<td>27,831</td>
<td>19,831</td>
<td>44,984</td>
<td>46,778</td>
<td>8.20</td>
</tr>
</tbody>
</table>

*The accumulated net weight of the CT workstring segment assumes circulation of 14.6 ppg brine through the CT ID and within the annulus.

Cutting testing included cuts of 2.00-in OD x 0.145-in wall thickness, 2.00-in OD x 0.156-in wall thickness, and 2.00-in OD x 0.175-in wall thickness tube. Along with these planned thicknesses of coiled tubing samples, there was an...
additional sample with an 0.185-in wall. Each piece of tubing was specified to be 110,000 psi. The tension on the coiled tubing at the time of cutting should represent the weight of the tube that is hanging below that point in the well. It is assumed that the first section with only the next higher size hanging below will be the hardest to cut; therefore, these are the conditions that were emulated. Each cut test was followed by a pressure test from below the ball. The test results are summarized in Table 3.

<table>
<thead>
<tr>
<th>Sample #</th>
<th>CT sample actual</th>
<th>Applied tension (lbf)</th>
<th>CT cut</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2-in OD x0.145-in W.T., CT100</td>
<td>0</td>
<td>Yes</td>
</tr>
<tr>
<td>2</td>
<td>2-in OD x0.156-in W.T., CT100</td>
<td>38,408</td>
<td>Yes</td>
</tr>
<tr>
<td>3</td>
<td>2-in OD x0.175-in W.T., CT100</td>
<td>45,200</td>
<td>Yes</td>
</tr>
<tr>
<td>4</td>
<td>2-in OD x0.184-in W.T., CT100</td>
<td>52,138</td>
<td>Yes</td>
</tr>
</tbody>
</table>

From the testing conducted, the SSTT ball valve was deemed capable of cutting the Petrobras tapered coiled-tubing string with the planned coiled-tubing tension applied. If the noted tension was not applied to the coiled tubing, then the ball valve operating pressure required for cutting coil tubing is anticipated to be higher. These coiled tubing cutting tests performed with the ball valve are unique and not deemed a standard type cutting test that can be applied globally (Figure 6). As a result of using the ball valve for cutting, the ball valve sealing capability could be compromised. Hence, this needs to be taken into consideration for well planning and risk mitigation scenario planning.

Figure 6. Cut samples of coiled tubing cut during the ball valve cutting tests.

5. Operations

Two of the three wells planned for the initial development phase, Phase 1, were completed: one well in Cascade and one well in Chinook. These wells were unique with many firsts, including the first lower-tertiary completion in the GOM, deepest well drilled and completed, deepest liner setting depth, deepest production tie-back casing operation, deepest tubing-conveyed perforating (TCP) operation, and deepest fractured interval. The completions in these two wells were performed without HSE incidents and within the planned cost and schedule.

The operations phase for the subsea landing string started with the first system integration test (SIT) performed in the field location prior to the completion of Cascade#4. During the SIT, critical interfaces were fully confirmed. This included mechanical and hydraulic interfacing of the SSTT, EH operating system with BOP project-specific equipment, newly developed technologies, and third-party tubing-hanger running tools (THRT).
Cascade#4 was completed in 8,200-ft WD with a hydrostatic pressure of 6,268 psi while Chinook #4 was completed in 8,850-ft WD with a hydrostatic pressure of 6,765 psi. The SSTT and EH operating systems were below rotary for 258 continuous hours with no lost time.

The original plan by Petrobras was to deploy the completion on Cascade#4 from the West Sirius and move the subsea landing string to deploy the completions on Chinook#4 from *Discovery Deep Seas*. The rig schedules overlapped and a second subsea landing string was required. The project team evaluated the configuration and space out of the second system utilizing existing inventory of equipment. A second tool was prepared, tested, and shipped to the *Discovery Deep Seas* in a short timeline.

6. Conclusions

Planning and preparation must be completed on time for any deepwater endeavor. One of the persistent difficulties in ultradeepwater completions is the variation in equipment design: subsea Christmas trees, downhole completion components, and BOPs are generally produced by different manufacturers for any single completion and can vary significantly from field to field. This diversity requires in-riser operating systems to include many custom interfaces with third-party equipment. The flexibility of the SSTT and EH operating system combination was proven several times during the project’s early phases.

Challenges due to the ultradeepwater and the high-pressure environments were overcome by the development of project-specific hardware, the product qualification and validation testing, and contingency planning. Risk identification and communication early in the project lifecycle allowed the project team time to perform the necessary engineering and qualification tests along with development of equipment such as the coiled-tubing cutter module which can preserve the SSTT valves to act as the primary subsea pressure barriers instead of making these a double-duty device.

Petrobras’s Cascade and Chinook developments demonstrated how challenges have been overcome by cooperation between Petrobras and service providers, as well as by the application of best practices. Best practices discussed include the retaining of planning project managers who worked closely with the client to understand project risks and enable the best solution.

8. References

YARNOLD, J., 5-1/2” I.D., 15K, Cutter Module, feasibility study, 2008.