HPHT Technology Verification, Validation, and Regulatory Requirements: HPHT Riser Technology Challenges

S. Dincal, N. Saglar, D. Reagan

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Abstract

Operators are looking to drill and develop deep-water wells with pressures over 15,000 psi and temperatures exceeding 300°F. Designing for high pressure, high temperature (HPHT) conditions present a number of engineering challenges, which can push conventional subsea technology designs to their limits. Therefore, there is a need to understand the feasibility of riser systems in these conditions and consequently to close any potential gaps between the current qualified technology and the outlined project specifications for a number of key riser components.

For conventional reservoirs, the merits of using wet tree and dry tree systems are well understood after years of design, fabrication, installation and operating experience. However, for HPHT riser applications, various design challenges exist with respect to the technology readiness of various riser system components of a wet or dry tree system development.

Key riser design issues and technology challenges, applicable to wet and dry tree HPHT systems, are addressed in this paper.

Introduction

Designing production riser systems for high pressure (up to 20ksi) and high temperature (up to 350degF) conditions present a number of engineering challenges, which can push conventional subsea technology designs to their limits. The merits of using wet tree and dry tree systems for conventional reservoirs are well understood after years of design, fabrication, installation and operating experience. However, for high pressure, high temperature (HPHT) riser applications, various design challenges exist with respect to the technology readiness of various riser system components of a wet or dry tree system development.

A typical steel catenary riser (SCR) configuration hung-off from a spar platform (Figure 1) and a typical top tensioned riser
(TTR) system supported from a Tension Leg Platform (TLP) (Figure 2) are shown as representative riser configurations for a wet and a dry tree production system, respectively. HPHT riser technology challenges associated with each production configuration, irrespective of the floating production platform, are summarized in this paper.

Figure 1 – Typical Steel Catenary Riser Configuration for a Spar
Figure 2 – Typical Top Tensioned Riser Configuration for a TLP
Wet Tree Design Challenges

The production of hydrocarbons using wet tree riser systems from an offshore reservoir mainly involves challenges and limitations associated with the large wall thicknesses due to HPHT environments. In order to discuss these limitations, a few case studies are performed to summarize the required wall thicknesses for different pressure/temperature combinations representative of HPHT environments.

It should be noted that a while a dry tree riser contains multiple hardware components to make up the system, in comparison, its wet tree counterpart is composed of very few components. Although the reduction in the number of components reduces the level of qualification required; the wet tree system has its own challenges.

Wall Thickness Sizing and Associated Limitations

For the purpose of this study, the wall thickness sizing is carried out in accordance with the following guidelines:

- 8 inch, 10 inch, and 12 inch API 5L [1] X65 and X70 seamless pipes are considered;
- Design pressures from 15 ksi to 20 ksi and temperatures up to 350 °F are considered;
- The wall thickness sizing is carried out per API RP 1111 [2];
- Temperature de-rating factor is applied to wall thickness calculations per API RP 2RD [3]. It should be noted that several other design codes provide more conservative temperature derating profiles than the profile proposed by API RP 2RD for steel pipes. Using more conservative temperature derating profiles will result in larger wall thickness at high temperatures;
- 0.118 inch (3 mm) corrosion allowance is assumed and included in the sizing calculations;
- The coefficient of the burst pressure equation is increased from 0.45 to 0.50 as per Appendix B of API RP 1111;
- For the burst pressure check, the riser design pressures are defined at the surface (mean sea level) and applied along the entire riser. Riser burst sizing is independent of water depth for this methodology.

The wall thickness results are presented in Table 1 through Table 3. The pipe wall thicknesses are driven by burst due to the high internal design pressure.

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<th>Design Temperature (°F)</th>
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Table 1 – 8 inch OD Pipe, WT Sizing Results

Learn more at www.2hoffshore.com
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Table 3 – 12 inch OD Pipe, WT Sizing Results

The field proven thickest wall to date for conventionally welded X65 single pipe wet tree production riser systems is 1.65 inch [4] [5]. The weldability of X65 line pipe with a wall thickness of 1.81 inch has been tested for offshore fatigue sensitive applications [6]. The industry is currently working on determining the weldability of X65 line pipes up to 1.9 inch. Therefore, in this paper, the maximum wall thickness that can be welded for offshore fatigue sensitive riser systems is assumed to be 1.9 inch. This wall thickness size is specified as an existing technology limit and is governed by challenges in terms of pipe fabrication, weldability, cladding application technology and successful AUT to achieve the required fatigue performance.

As shown in Figure 3, the pipe wall thicknesses required for 8 inch OD pipe for the specified design pressures (up to 20 ksi) and temperatures (up to 350 °F) are below the existing technology limit (1.9 inch WT). For 10 inch OD pipe, existing technology limit can only provide a capacity up to 15 ksi design pressure. Design pressure of 17.5 ksi and above may not be feasible for a 10 inch OD pipe with the existing technology limitations, as shown in Figure 4. 12 inch OD pipe may not be feasible to use for HPHT conditions per the existing technology limitations as shown in Figure 5.

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8 inch OD, Wall Thickness Sizing for Different Ranges of Design Pressures and Temperatures

Existing Technology Limit = 1.9inch

Figure 3 – 8 inch OD Pipe, WT Sizing Results

10 inch OD, Wall Thickness Sizing for Different Ranges of Design Pressures and Temperatures

Existing Technology Limit = 1.9inch

Figure 4 – 10 inch OD Pipe, WT Sizing Results
Pipe Fabrication Challenges
With the need for thick walled pipes used in HPHT applications, the pipe manufacturing process becomes more challenging considering the following critical points:

- Thick wall pipe sections;
- Lower D/t ratios;
- Pipe inspection and quality control of production of heavy wall pipe;
- Obtaining optimum pipe microalloy composition while meeting desired mechanical properties;
- Meeting desired hardness values for sour service applications and resistance to sour service;
- Heavier pipe sections and hence shorter pipe joint lengths;
- Achieving targeted pipe dimensional tolerances;
- Advanced heat treatment processes and material handling tweaks;
- Uniformity of pipe properties through thick wall pipe section;
- Excessive hydrostatic pressures and limiting equipment capabilities in pipe mills.

Welding Challenges
Increasing the pipe wall thickness will result in major challenges for welding:

- Thick pipe wall has the potential for increased hardenability of the heat affected zone (HAZ) and weld metal;
- Increase in wall thickness may lead to a risk of poorer fracture toughness response, especially in the HAZ;
- With increased pipe wall, multiple weld passes will be required. High number of weld passes and high quality output requirements could be a potential risk;
- Design temperatures may lead to elevated temperature testing, challenge to obtain the weld metal within desired limits;
- Counterboring would be required to achieve critical hi-lo values to be able to obtain fatigue sensitive quality weld profile;
- Weld equipment development and modification work may be required for depth of weld bevel groove;
- Shielding gas may be a concern at that depth of bevel groove to provide adequate weld pool shielding;
- AUT inspection could be a concern at that depth of bevel groove to capture fatigue sensitive flaw sizes.

Installation Challenges
The weight of thick wall risers is an issue for installation. There are only a limited number of installation vessels able to install thick wall SCRs in deepwater and the number starts to diminish rapidly as water depth, pipe diameter and wall
thickness increase. Especially, feasibility of using reel-lay diminishes as the water depth exceeds 10,000 ft as the top tension exceeds reel lay vessels’ tension capacity.

Installability of the HPHT production risers is evaluated based on the top tension of the SCRs. The riser weight during installation is considered based on fully flooded cases. The suspended length of the riser is calculated using catenary equations as a function of hang-off angle and water depth. The assessment considers risers with 12° installation departure angles from vertical using a reel lay installation vessel. For the purpose of the assessment, a dynamic amplification factor of 1.25 is applied on the static riser weight during installation to account for dynamic loading from vessel motions during installation.

8 inch, 10 inch, and 12 inch X65 pipes are considered. Design pressures from 15 ksi to 20 ksi and the maximum design temperature of 350 °F are considered, corresponding wall thicknesses are then used to calculate the top tension of the production risers. Production riser top tension requirements vs. water depth are plotted in Figure 6. The tension capacity of reel lay installation vessels is considered to be 2,200 kips (1,000 mT). Hence, the feasible SCR applications are identified using vessel payload of 2,200 kips.

Top tension calculated for the riser installations cases are found to be within the tension capacities of the reel lay installation vessels for 8 inch SCRs at the design conditions and water depths assessed. For 10 inch SCRs, reel lay installation becomes less feasible as water depth approaches to 10,000 ft and design pressures exceed 15 ksi. 12 inch SCRs are not feasible to be installed via reel lay for any water depth above 7,000 ft while the riser is filled with seawater.

![Figure 6 – SCR Installation Tension Requirements](image)

**Hang-off System Challenges**

Typically, two hang-off systems have been used in wet tree riser applications, namely flexible joints and tapered stress joints.

The current flexible joints have been used up to approximately 13 ksi design pressure and 250 °F design temperature. For HPHT conditions, the current flexible joint technology may not be adequate as a hang-off system. Advanced flexible joints systems are required as a hang-off system, which will be a departure from the existing flexible joint design installed to date and hence will require significant design and qualification effort.

Steel tapered stress joints can be used as a hang-off system. However, due to high tension at the top of the riser because of thick wall pipe, steel stress joints could be challenging due to limits on forging length, wall thickness, weight restrictions and loads into hull. As a second option, titanium tapered stress joint can be used as a hang-off system. Titanium provides higher strength and lower bending stiffness compared to steel and could be more feasible for the HPHT applications. However, it should be noted that hydrofluoric (HF) acid, which may be used for acidizing wells, attacks titanium very quickly. Any HF
containing acids should be avoided in all cases for titanium riser sections due to severe rapid uniform corrosion attack.

**Considerations Regarding Fatigue**

Meeting target design fatigue lives could be challenging under HPHT service conditions. Per API-TR-17TR8 [7], the technical report that serves as a design guideline for HPHT equipment, HP wells should be considered as sour with the possibility that the H₂S content may increase over the life of the well and the required H₂S concentration to establish sour service condition (as defined by NACE MR0175/ISO 15156 [8]) is below the limit for reliable analysis of H₂S concentration (i.e., low percentage concentration of H₂S may actually be sour service due to a high partial pressure H₂S).

In order to improve the fatigue performance of the risers in fatigue sensitive regions (e.g., touch down zone (TDZ) in SCRs), fatigue mitigation strategies could be considered in design, which may include:

- Counterbored riser pipe;
- Weld-on thick forged ends in the TDZ;
- Integrally machined pilger pipe upset ends in the TDZ;
- Titanium TDZ;
- SCR with discrete buoyancy modules just above TDZ, and;
- ID pipe cladding along the fatigue critical locations.

Each fatigue mitigation option shall be evaluated and compared for the following criteria:

- S-N fatigue life (fatigue performance);
- Commercial viability, and;
- Technology development status.

**The use of High Integrity Protection Systems (HIPPS) to Address the Heavy Wall Thickness Requirements**

In order to address the challenges and limitations associated with the large wall thicknesses due to HPHT environments, a viable option for field development is to utilize HIPPS (High Integrity Pressure Protection Systems) within the subsea architecture. HIPPS are mechanical and electrical-hydraulic SIS (safety instrumented systems) used to protect production assets from high-pressure upsets [9]. The full internal product pressure may be contained by the HIPPS at the seabed, which allows the use of lower pressure hardware downstream of the spec break. A fortified section located downstream of the HIPPS isolation valves is required to allow time to respond to the system closure determined by the pressure transient calculations. HIPPS will reduce: (1) Topsides pressure; (2) Flowline and riser wall thickness (and therefore may offer the potential to use the existing, lower pressure flowlines and risers); (3) Offshore welding time. Downstream of the spec-break the subsea production system could be de-rated for lower pressures passed the fortified zone using HIPPS units and larger flowlines should be used to enhance the production flow rates substantially.

**Dry Tree Design Challenges**

The production of hydrocarbons from an offshore reservoir through a top tensioned riser (TTR) dry tree system requires both surface and subsea riser hardware. Requirements detailed in Title 30, Chapter 250, Section 250.733 of Code of Federal Regulations (CFRs) states that for risers installed after July 28, 2016, use of a dual riser configuration before drilling or operating any hole section or interval where hydrocarbons are, or may be, exposed to the well, [10].

While the regulation states that a dual riser configuration is required it does not explicitly state the pressure requirement of the inner and outer bore. Traditionally, for production TTRs, the inner riser is designed for full shut-in tubing pressure (due to tubing leak) as an extreme load condition. However, industry practice so far, is to utilize the outer bore as an environmental barrier designed for collapse loads only. Alternatively, to introduce additional robustness to the overall riser system, a “No-Burst Design” philosophy can be adopted in which the outer riser is designed not to burst under the maximum anticipated shut-in well pressure in case inner riser leaks while exposed to full hydrocarbons to the surface.

API-RP-1111 [2] Annex A prescribes procedures for determining the burst design criteria for pipes that exhibit ductility and fracture toughness properties, which will lead to ductile failure modes in burst, tension, bending, collapse, and combined loading. Two reference parameters, namely the capped end yield pressure (CEYP) and the capped end burst pressure (CEBP), are defined as part of the test procedure designed for determining an accurate burst pressure of a pipe. It is noted that the capped end burst pressure is close to, but usually less than, the actual burst pressure of the pipe.
**Surface Jumper Assembly**

Topside flexible jumpers convey production fluid between the surface tree and the production topsides piping and are designed based on API Specification 17J. Selection of the correct flexible jumper materials and design are typically project specific (i.e., flexible jumpers are not off the shelf components). As most HPHT projects are yet to be developed and sustained long term operations it is prudent to perform a detailed design and qualification program for any flexible jumper placed into HPHT application. Details on the HPHT flexible jumpers currently in use are detailed in [11].

During design and qualification focus should be placed on the selection of the internal carcacas material for high temperature applications. Temperatures exceeding 150°F (65°C) will typically require the use of polyvinylidene fluoride (PVDF) internal carcass. In addition to temperature effects of wellbore, well stimulation and completion fluid should be evaluated to verify they will not degrade the internal carcass.

An additional challenge to HPHT flexible jumper design is fatigue. Fatigue in topside jumpers is driven by the motions of the vessel relative to the tree, pressurization and depressurization as well as fretting fatigue between armor layers. Due to the relative motion between the tree and the topsides dynamic tensile and bending loads are applied to the jumper and end fittings causing fatigue damage. Throughout the life of a TTR the system will go through cycles of production and shut in. Each time the flexible jumper goes through a pressure cycle strain is imparted on the wires causing fatigue damage. As detailed in [11] high pressure flexible require multiple pressure layers, as these layers move against each other fretting can occur leading to excessive wear and potential failure. Fretting fatigue is only exaggerated further when high pressure are placed on the flexible.

A final challenge is providing a bore diameter that meets the project completion/operation plan while providing a sufficient minimum bend radius (MBR) to fit into a vessel wellbay. End to end spacing of flexible jumpers is critical to prevent damage to the assembly during installation and operation. The stiffer the flexible jumper is the larger the MBR will be which requires increased end to end separation. The increased end to end spacing increase the likely hood of utilizing bend stiffeners, bend restrictors or sleeves to protect the flexible jumper from wear and tear during operations. Even before the requirements of HPHT systems there are multiple platforms currently in the GoM that have flexible jumpers installed in less than desirable configurations due to the lack of planning during the development of the wellbay and topside.

A potential mitigation to the risks associated with HPHT flexible jumpers on TTR is to place the topside choke on the surface tree rather than the topside processing. By placing the choke at the tree pressure can be reduced below 15,000 psi thus eliminating some of the flexible jumper design and qualification challenges. Each operator will have their own philosophy on the risks associated with placing the choke on the tree, however a detailed risk assessment with safe guards provided to prevent potential risks will make this a feasible option.

**Surface Wellhead and Tree**

Referring to API Specification 6A, [12] surface wellhead are manufactured with various internal diameters as well as pressure ratings. When duel casing top tensioned risers are utilized, surface wellhead sizes are typically either 13-5/8” or 18-3/4”. The ID of the wellhead is defined by the operator based on the drill, complete and workover operations that will take place throughout the life of the system.

The surface wellhead and tree is composed of various components making the design and qualification complicated. To determine the qualification level the end operator must evaluate the following:

- Mechanical loading of connection between tension joint and surface wellhead;
- Rated working pressure of seal between tension joint and surface wellhead;
- Surface wellhead body;
- Casing hanger (load bearing components and seal);
- Surface wellhead outlet valves;
- Mechanical connection and seal between the surface wellhead and tubing head;
- Tubing head;
- Tubing hanger (load bearing components and seals);
- Tubing hanger outlet valves;
- Penetrators on tubing head;
- Mechanical connection and seal between tubing head and tree valve assembly;
- Tree valve assembly;

While many of the interfaces listed above are standard to all wells and have extensive qualification testing, there are a few that still have not been field proven for HPHT wells. If drill and complete plan requires the use of an 18-3/4” surface
wellhead a 18-3/4” 20 ksi Casing Hanger Annulus Seal will be required for the inner riser. To achieve an acceptable seal, API Specification 6A Annex F performance testing shall be carried out. This testing is especially difficult for elastomeric seals and rapid explosive decompression should be considered during testing. Detailed design reviews of test fixture should be conducted to verify that the test fixture meets the requirements of the codes and that fixture allows the seals to be tested the same way they will be operated in the field.

In addition to sealability testing per API Specification 6A a combination of pressure and load should be applied. The loads that are applied during testing should be developed based on the global performance modeling of the TTR system. Load testing should include a combination of pressure, tension and bending and should include both maximum anticipated loads as well as cyclic loading (ratcheting). Test of this sort can be time consuming and difficult to develop in a shop setting so a clear understanding of the qualification protocol is required to be developed prior to execution of component design and testing.

An often overlooked component in the surface equipment is the tubing head penetrators. Most of the penetrators are supplied by non wellhead and tree suppliers and therefore have to be integrated into the design. The testing of these penetrators is often done in isolation of the tubing head manufacture and may not consider the difficulties associated with the actual installation at the work site. Tight tolerance required on the penetrators can lead to damage of the penetrators during installation which can potentially void qualification testing that was performed.

Another seal that will require qualification testing is the 13-5/8” connection between the tree valve assembly and tubing head. Depending on the loads calculated from the global performance analysis both load testing and seal qualification may be required for this connection.

**Tensioner System**

The tensioner systems and the cylinders which make up the system do not contain or control hydrocarbons. Because they are not pressure containing or controlling there is not one specific oil and gas code or standard utilized in the development of them. Each system has to follow a host of standards in order to be able to meet the requirement for implementation into and offshore platform. A few of the key codes and standards are

- Cylinder barrels - ASME Section VIII, Division 1 or Section VIII, Division 2 PVM-SU-8.00, “General Specification for Pressure Vessels”
- Cylinder piston/rod - Allowable Stress per ASME Section VIII
- Tension ring - API RP 2RD, “Design of Risers for Floating Production Systems (FPSs) and Tension Leg Platforms (TLPs)”
- Electrical – NFPA 70 “National Electric Code”, Article 497 “Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas”

During the global riser design process the tensioner response is a key input into the design. If the tensioner system is not modeled correctly the system can experience higher loads or larger displacements. In order to apply a consistent top tension to the riser and allow for motions of the vessel a hydro pneumatic tensioner system connects to the upper portion of the riser. The tensioner system is typically operated with nitrogen filled barrels which apply a force to the rod that is internal to the barrel. As the vessel offsets or moves due to the environment the rod will stroke through the barrel causing the pressure and volume of the gas in the barrel to change.

The change of pressure and volume in the barrel can be described through the thermodynamic polytropic process. The polytropic process is defined through the following equation:

\[ P V^n = C \]

Eq. 1

Where,
While the equation is simplistic in nature the difficulty in the equation is determining the correct polytrop index value. Accurately predicting the value can be difficult but typically ranges from 1.1 to 1.4 for large pneumatic style cylinder utilized for tensioner systems. A polytropic index of 1.1 has been shown to provide accurate tensioner stroke range thus reducing the likelihood of clashes of riser equipment with topsides equipment. However, a polytropic index of 1.4 is appropriate for higher oscillation velocities of the tensioner cylinder during a hurricane event and provides some conservatism to riser loading in lesser environments thus providing the loading that will be transferred from the riser system to the topsides.

The best method for determining the polytropic index is to build a prototype cylinder and conduct testing on the cylinder to determine the correct value to be used. In order for this information to be available for project execution this work should be conducted during the front end engineering and design (FEED) if nonstandard tensioner systems are required.

Control Umbilical

The control umbilical provides electrical power to the downhole Subsea Surface Safety Valves (SSSV), Electrical Submersible Pumps (ESPs), if applicable, as well as communication with wellhead and tree sensors. The control umbilicals are designed based on API 17E. Hydraulic hoses provide control ability for surface tree and wellhead valves as well as communications and chemical injection capabilities. Like the flexible jumper, the control umbilical must accommodate movement of the tree in the vertical and lateral directions while not compromising the manufacturer’s MBR.

For control umbilical there are typically three hose sizes required for the various operations the umbilical needs to provide a conduit for. At this time there are no field proven 20 ksi umbilical’s hoses that are installed thus making the control umbilical for a HPHT development a key piece of the engineering. As there are no field proven 20 ksi umbilicals, qualification for the high pressure hoses has not been required and has not been completed for all hose sizes.

There is ongoing qualification for the 1/4” and 3/8” lines however difficulties have been seen during qualification. Failures at the interfaces between the hoses and end terminations have proven to be difficult to overcome. While 1/4” lines are close to completing qualification, larger lines have been put on hold due to slow down in industry interested. The learnings from the 1/4” qualification tests will be carried over to the larger lines, however scaling for high pressure applications has proven to provide inconsistent results.

Upper and Lower Stress

The upper stress/tension joint is a specialty designed components used to manage the stress levels at the top of the riser system. The joint is designed to the requirement of API recommended practice or standard 2RD. Typically the component is an 80 ksi grade steel forging with an integral connector to interface with the surface wellhead at the upper end and an integral connector at the lower end to interface with the riser joints.

The joint is typically much larger than other joints and make up of the joint to the riser system is performed on the rig floor. As the mass of the joint is greater than standard riser joint the make up of the joint to the riser string cannot be performed through the use of standard tongs on the rig floor. For this reason an integral flange connection is typically manufactured to the bottom of the tension joint so that studs and nuts may be used for the make up of the joint to the riser system.

HPHT systems have shown to have increased bending and tensile loads at these joints thus making them longer and thicker walled. Studies have shown that specialty tension joints for an HPHT system require a length that is greater than current manufactures capabilities. An option to resolve this may be to create a two part stress joint connected via a flange connection. The flange connection will be required to be forged integral to the joint to avoid welds in fatigue critical areas however flange stress joints are field proven in such cases as a keel guide on a Spar.

Whether it is a single or two part stress joint, both are long lead items requiring significant design iterations to verify that the localized stresses in the joint do not exceed codes and standards. In addition, if a two part stress joint is required the flange must also go through a design review and potentially validation such as:

- Full scale testing with respect to functionality, including make up and breakout, and performance under dynamic loading and extreme static loading;
- Seal functionality including:
  - Capped end pressure cycling;

Learn more at www.2hoffshore.com
- Tension and internal/external pressure cycling;
- Bending and internal/external pressure cycling;
- Capped end pressure with increasing tension to failure test;
- Full scale strain gauge validations against known FEA results;
- Full scale fatigue testing, inclusive of flange and welds.

**High Strength Steel Riser Joints**

The ID of the inner riser is determined based on the drift requirements of the downhole completions tools but is typically either 9.5 or 10.5 inches. As previously discussed in addition to the inner riser pressure barrier a second pressure barrier shall be present for Gulf of Mexico (GoM) operations. The drift diameter of the outer riser should be sized both on the completion equipment as well as the OD of the internal tieback connector. With both the drift requirements of the inner and outer riser know wall thickness sizing per API-RP/STD-2RD can be performed to determine the required wall thickness.

There are several different types of joints that make up the outer riser. For a Tensioned Leg Platform (TLP) riser system both standard riser joints as well as splashzone joints are required. Due to the hull form of a Spar splash zone joints are not required, however a keel joint is. Details for riser joints design and material selection are discussed in detail in paper [13].

Inner and outer riser joints are designed to be manufactured in accordance with API 5CT. API 5CT details the mechanical and inspection requirements for manufacturing of the pipe material, however the wall thickness design of the riser joints is based on utilizing a burst equation with a coefficient of 0.50 from API-RP-1111, which requires burst testing. Performing burst testing to such high pressure has proven to test the limitations of some pipe suppliers and the methodologies should be discussed. In addition to burst testing as HPHT wells are inherently sour, sour service testing of the production material should be completed. API 5A5 and 17G can be utilized for test the T&C connections.

**External Tieback Connector**

The external tieback connector (ETBC) is a hydraulic connector actuated by a remotely operated vehicle (ROV). When hydraulic pressure is applied to the connector a locking ring becomes energized and interfaces with a profile on the subsea wellhead. By energizing the lock ring into the subsea wellhead a preload at the base of the riser is generated. The pre-load is sufficient to keep the lower riser connected to the subsea wellhead through all loading scenarios. While HPHT systems demonstrate higher bending loads at the ETBC, recent studies of HPHT TTR suggest that the current ETBC offered by equipment suppliers is sufficient to handle these loads.

Additionally, a seal profile is cut in the ETBC or bottom of an integral stress joint. A wellhead gasket is installed between the ETBC and subsea wellhead to act as a pressure barrier. Wellhead gaskets are qualified to API Specification 6A, Annex F testing, however most manufactures have qualified gasket for HPHT systems.

**Internal Tieback Connector**

The internal tieback connector (ITBC) provides a means of load transfer of the inner riser to the subsea wellhead as well as forms a seal between the inner and outer riser bore in the event of a tubing leak or pressure kick during workover. As such both the loading on the ITBC as well as the sealability require testing. While most components within the hydrocarbon production system have well defined codes and standards to follow for design and qualification, the ITBC is not clearly defined in any industry code or standard. To further complicate the matter the subsea wellhead arrangement for each project will likely be different thus make it almost impossible to find a qualified ITBC that has been tested to the project specific subsea wellhead interface and requirements.

In regards to the qualification of the ITBC It can be argued that the component falls into API specification 17D and therefore should be qualified to 17D requirements, however the upper end of the ITBC typically has an OD and wall thickness that matches the API-RP/STD-2RD riser system and therefore is not designed for the 1.5 times working pressure testing required by 17D.

For seal qualification the most commonly accepted methodology for testing the ITBC is to perform an API 6A Annex F style test. This includes applying pressure as well as upper and lower bound temperature to the seal while monitoring pressure drop and leakage rates. As API 6A does not specifically cover ITBC the risk assessment should be evaluated to determine the allowable leakage rate during the testing. Additional API 6A annex F has methods for testing one side or both sides of the seal. The risk assessment should be evaluated to determine the appropriate testing regime.

While surface equipment does not have the luxury of utilizing differential pressure as they operate in atmospheric pressure, the ITBC is at the base of the water column. When the ITBC is exposed to high internal pressures it also has an external pressure due to the hydrostatic head associated with the water column. Both API Technical Recommendation 17TR8
and 17TR12 [14] may be evaluated for use in the specific application. When utilizing differential, it is prudent to evaluate areas between primary seals and secondary seal where atmospheric pressure may be trapped.

**Dry Tree Technology Readiness**

It can be shown that within the oil and gas sector each operator has their own definitions and methodologies for defining how qualified a component is and what it technology readiness is for field use. As it is not efficient to evaluate each piece of equipment for various operators, for the purposes of this paper the definition from API Recommended Practice 17N, [14] are used. The definitions of TRL from API-RP-17N, [15] are summarized in Table 4. Based on recent surveys of equipment providers the following technology readiness has been found for dry tree TTR hardware.

<table>
<thead>
<tr>
<th>Component</th>
<th>TRL Range</th>
<th>TRL Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>18-3/4” Wellhead</td>
<td>7</td>
<td>Field Proven</td>
</tr>
<tr>
<td>18-3/4” &gt;15 ksi Casing Hanger</td>
<td>1&lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>Proven Concept</td>
</tr>
<tr>
<td>Casing Head Outlet Valves</td>
<td>7</td>
<td>Field Proven</td>
</tr>
<tr>
<td>13-5/8”&gt;15 ksi Connection and Seal Between Tubing Head and Wellhead</td>
<td>1</td>
<td>Proven Concept</td>
</tr>
<tr>
<td>13-5/8” Tubing Hanger</td>
<td>7</td>
<td>Field Proven</td>
</tr>
<tr>
<td>Tubing Head Penetrations</td>
<td>5</td>
<td>System Tested</td>
</tr>
<tr>
<td>13-5/8” &gt;15 ksi Connection and Seal Between Tree Valve Assembly and Tubing Head</td>
<td>0</td>
<td>Unproven Concept</td>
</tr>
<tr>
<td>4-1/16” 20 ksi Valve Assemblies</td>
<td>7</td>
<td>Field Proven</td>
</tr>
<tr>
<td>Tensioner System</td>
<td>7</td>
<td>Field Proven</td>
</tr>
<tr>
<td>Flexible Jumper Pipe</td>
<td>3</td>
<td>Prototype Tested</td>
</tr>
<tr>
<td>Flexible Jumper End Fitting</td>
<td>7</td>
<td>Field Proven</td>
</tr>
<tr>
<td>Umbilical</td>
<td>1 - 2</td>
<td>Validated Concept</td>
</tr>
<tr>
<td>Upper stress/Tension Joint</td>
<td>7</td>
<td>Field Proven</td>
</tr>
<tr>
<td>Riser Joints and Connectors</td>
<td>5&lt;sup&gt;(2)&lt;/sup&gt;</td>
<td>System Tested</td>
</tr>
<tr>
<td>Lower Stress Joint</td>
<td>7</td>
<td>Field Proven</td>
</tr>
<tr>
<td>External Tieback Connectors</td>
<td>7</td>
<td>Field Proven</td>
</tr>
<tr>
<td>Inner riser joint</td>
<td>5&lt;sup&gt;(2)&lt;/sup&gt;</td>
<td>System Tested</td>
</tr>
<tr>
<td>ITBC</td>
<td>2</td>
<td>Validated Concept</td>
</tr>
</tbody>
</table>

Notes
1/ Potential to be increased to a 4 if technology from subsea wellhead system can be utilized in surface equipment
2/ Dependent on wall sizing calculations meeting tested sizes

Table 4 – Dry Tree TTR Hardware Technology Readiness

**Conclusions**

Production from HPHT reservoirs poses an challenging problem as all hardware being put into service could be considered new technology and there is still no complete field proven solution available for either a wet tree or dry tree production system. Project specific risk assessments are required to determine the acceptability of each component. While there are currently industry codes and standards for performing qualification work, they should be implemented in conjunction with a detailed risk assessment to verify the new operating environment of HPHT reservoirs is adequately addressed and validated. TTR surface trees, flexible jumpers, control umbilical, inner and outer riser joints as well as internal tieback connectors all require qualification prior to project execution. Weld procedures and material processing need to be evaluated in detail to ensure the heat affected zones will meet the project mechanical requirements. In addition to pipe fabrication and welding challenges, HPHT wet tree riser systems involve hang-off challenges due to pressure limitations, installation challenges due to weight restrictions and may require novel fatigue mitigation strategies to achieve production design life.

**Nomenclature**

- API – American Petroleum Institute
- D/t – Diameter to wall thickness
- DNV – Det Norske Veritas
- RP – Recommended Practice
- T&C – Threaded and Coupled
- TDZ – Touchdown Zone

Learn more at www.2hoffshore.com
ETBC – External Tieback Connector, TDP – Touchdown Point
FMECA – Failure mode, effects and criticality analysis, Ti – Titanium
HF – Hydrofluoric Acid, TLP – Tendon Leg Platform
HPHT – High Pressure High Temperature, TRL – Technology Readiness Level
ID – Internal Diameter, TSJ – Tapered Stress Joint
ITBC – Internal Tieback Connector, TTR – Top Tensioned Riser
ksi – Thousand Pounds per Inch, SCR – Steel Catenary Riser
MBR – Minimum Bend Radius, STD – Standard
mm – Millimeter, WPQ – Weld Procedure Qualification
OD – Outer Diameter, WT – Wall Thickness

References