High-Pressure High-Temperature (HPHT) Design Guidelines

API TECHNICAL REPORT 17TR8
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1. Scope

The scope of this technical report is for the design evaluation of oil and gas equipment utilized in high-pressure high-temperature (HPHT) environments. For the purpose of the technical report, HPHT environments are intended to be one or a combination of the following well conditions:

1) The completion of the well requires completion equipment or well control equipment assigned a pressure rating greater than 15,000 psig (103.43 MPa) or a temperature rating greater than 350°F (177°C);

2) The maximum anticipated surface pressure or shut-in tubing pressure is greater than 15,000 psig (103.43 MPa) on the seafloor for a well with a subsea wellhead or tied back to the surface and terminated with surface operated equipment; or

3) The flowing temperature is greater than 350°F (177°C) on the seafloor for a well with a subsea wellhead or tied back to the surface and terminated with surface operated equipment.

Service temperature ratings above 550°F (288°C) are not within the scope of this technical report.

The equipment items within the scope of this technical report are listed under the API SC17 series, addressing one or a combination of the following loading conditions:

1) Internal and external pressure

2) Ambient and elevated operating temperatures

3) Static and dynamic mechanical loads

4) Pressure/temperature induced loadings

This technical report is intended to serve as a general design guideline for HPHT application. Specific SC17 recommended practices and specifications may elect to adopt portion or all of the presented guidelines for HPHT application, subject to their component hardware and application-related design constraints. Other API product standards, e.g., API 6A, API 16A, may elect to adopt portion or all of this technical report, also subject to their component hardware, application-related design constraints, and acceptance criteria.

This technical report is intended to provide design guidelines for: pressure-containing (pressure vessel), seals and fastening components that comes in contact with or is immediately adjacent to wellbore fluids operating at HPHT conditions. Additionally, intra-field piping systems (e.g., flowlines and pipeline jumpers, manifold piping, valving and connectors, and intervention riser equipment) are is within the scope of this technical report. The design methodology referenced in this technical report may also be applied to pressure-controlling components, if the design methodology can appropriately assess the applicable failure mode(s).

This technical report is not specifically intended to cover oil-country tubular goods (OCTG) for drilling or completing wells nor is it intended to cover downstream pipeline or production riser design, nor downhole component hardware that may be subject to additional application-related design constraints. Structural members or ancillary equipment associated with HPHT hardware but not working in close proximity to the HPHT environment is not within the scope of this technical report.

The main topics for this technical report are categorized as:

1) Design Verification: Design verification focuses on analytical methods to verify the mechanical integrity and life-cycle assessment of the proposed design.

2) Materials for HPHT Equipment: The material section defines the required input parameters for the design verification process and recommends the procedures necessary to evaluate the material’s properties for the intended service environment.

3) Seals and Fasteners: The seals and fasteners sections provide guidance on these specific elements of the design as they impact, or are impacted by the HPHT designs.
4) Design Validation: The design validation section focuses on demonstrating the reliability of the equipment’s design and can include defining the appropriate validation methods to analyze and mitigate the failure modes identified from the failure modes, effects and criticality analysis (FMECA).

2. Normative References

The following are normative references to this technical report:

- API Standard 6X, Design Calculations for Pressure-Containing Equipment, PENDING

3. Terms, Definitions, Acronyms, Abbreviation, and Symbols

3.1 Definitions

For the purposes of this technical report, the following definitions shall apply.

3.1.1 Autofrettage
Phenomenon associated with the inner wall of the pressure vessel showing material approaching or exceeding the material’s yield strength while further way from the bore, material stress decreases well below the yield strength.

3.1.2 Cast or heat analysis
[Ladle analysis (obsolete)]
Chemical analyses representative of a heat of metal as reported to the purchaser and determined by analyzing a test sample obtained from the molten metal, for the elements designated in a specification.

3.1.3 Check or Verification Analysis
That which defines the limits of acceptability of the chemical composition of a material when the analysis is over or under the maximum or minimum specified value of an element; performed on a finished or semi-finished component, and is not used by the producer for heat analysis acceptance testing.

3.1.4 Corrosion-Resistant Alloy
CRA
A nonferrous-based alloy in which the amount of any one element or the sum of the specified amount of the elements exceeds 50% (mass fraction).

NOTE Elements include titanium, nickel, cobalt, chromium, and molybdenum.

3.1.5 Fracture Toughness
Property of a material that measures the resistance-to-failure resulting from crack propagation.

3.1.6 Functional Specifications
Document generated by the user/purchaser that specifies the design parameter requirements and operating conditions, as appropriate.
3.1.7
High-Pressure High-Temperature
HPHT
Reference to wells with a potential pressure greater than 15,000 psig (103.43 MPa) at the wellhead, or with a potential temperature greater than 350°F (177°C) at the wellhead.

3.1.8
Operational Cycle
Initiation and establishment of new conditions, from both internal and external operational loads, followed by a return to the conditions that prevailed at the initiation of the cycle.

3.1.9
Plastic Collapse Load
Load that causes overall structural instability of a component/equipment; indicated by the inability to achieve an equilibrium solution for a small increase in load.

3.1.10
Pressure-containing
Part whose failure to function as intended; results in a release of wellbore fluid to the environment.

3.1.11
Pressure-controlling
Part that is intended to control or regulate the movement of pressurized fluids.

3.1.12
Product Analysis
Chemical analysis of the semi-finished or finished product, usually for the purpose of determining conformance to the specification requirements.

NOTE   The range of the specified composition applicable to product analysis is normally greater than that applicable to heat analysis in order to take into account deviations associated with analytical reproducibility and the heterogeneity of the metal.

3.1.13
Ratcheting
Progressive incremental inelastic deformation or strain which can occur in a component that is subjected to variations of mechanical stress, thermal stress, or both.

3.1.14
Stress Cycle
Condition in which the alternating stress difference goes from an initial value through an algebraic maximum value and an algebraic minimum value, and then returns to the initial value.

NOTE   A single operational cycle may result in one or more stress cycles.

3.1.15
Ultimate Tensile Strength
UTS
Maximum stress that a material can withstand while being stretched or pulled before failing or breaking.

3.1.15
Yield Strength
YS
Engineering stress at which, by convention, is considered that plastic elongation of the material has commenced.

3.2   Acronyms & Abbreviations

For the purposes of this technical report, the following acronyms and abbreviations shall apply.

ANSI   American National Standards Institute
API    American Petroleum Institute
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>ASM</td>
<td>American Society for Metals</td>
</tr>
<tr>
<td>ASME</td>
<td>American Society of Mechanical Engineers</td>
</tr>
<tr>
<td>ASNT</td>
<td>American Society for Nondestructive Testing</td>
</tr>
<tr>
<td>ASTM</td>
<td>American Society for Testing and Materials</td>
</tr>
<tr>
<td>BPVC</td>
<td>(ASME) Boiler and Pressure Vessel Code</td>
</tr>
<tr>
<td>BS</td>
<td>British Standards</td>
</tr>
<tr>
<td>CP</td>
<td>cathodic protection</td>
</tr>
<tr>
<td>CRA</td>
<td>corrosion-resistant alloy</td>
</tr>
<tr>
<td>CTOD</td>
<td>crack tip opening displacement</td>
</tr>
<tr>
<td>CVN</td>
<td>charpy V-notch</td>
</tr>
<tr>
<td>DCB</td>
<td>constant displacement tests</td>
</tr>
<tr>
<td>DNV</td>
<td>Det Norske Veritas</td>
</tr>
<tr>
<td>ET</td>
<td>eddy current testing</td>
</tr>
<tr>
<td>FCGR</td>
<td>fatigue cracking growth rate</td>
</tr>
<tr>
<td>FEA</td>
<td>finite element analysis</td>
</tr>
<tr>
<td>FMECA</td>
<td>failure modes, effects and criticality analysis</td>
</tr>
<tr>
<td>FM</td>
<td>fracture mechanics</td>
</tr>
<tr>
<td>FT</td>
<td>fracture toughness</td>
</tr>
<tr>
<td>HIC</td>
<td>hydrogen-induced cracking</td>
</tr>
<tr>
<td>HISC</td>
<td>hydrogen-induced stress cracking</td>
</tr>
<tr>
<td>HP</td>
<td>high-pressure</td>
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<tr>
<td>HPHT</td>
<td>high-pressure high-temperature</td>
</tr>
<tr>
<td>HT</td>
<td>high-temperature</td>
</tr>
<tr>
<td>HRC</td>
<td>Hardness Rockwell C</td>
</tr>
<tr>
<td>ISO</td>
<td>International Organization for Standardization</td>
</tr>
<tr>
<td>ITP</td>
<td>inspection and test plan</td>
</tr>
<tr>
<td>kPa</td>
<td>kiloPascal</td>
</tr>
<tr>
<td>ksi</td>
<td>1,000 pounds per square inch</td>
</tr>
<tr>
<td>LAS</td>
<td>low alloy steel</td>
</tr>
<tr>
<td>LAST</td>
<td>lowest anticipated service temperature</td>
</tr>
<tr>
<td>LBB</td>
<td>leak-before-burst</td>
</tr>
<tr>
<td>MDMT</td>
<td>minimum design metal temperature</td>
</tr>
<tr>
<td>MPS</td>
<td>manufacturing procedure specification</td>
</tr>
<tr>
<td>MPa</td>
<td>megaPascal</td>
</tr>
<tr>
<td>MT</td>
<td>magnetic particle testing</td>
</tr>
<tr>
<td>NACE</td>
<td>National Association of Corrosion Engineers</td>
</tr>
<tr>
<td>NDE</td>
<td>nondestructive examination</td>
</tr>
<tr>
<td>NIST</td>
<td>National Institute of Standards and Technology</td>
</tr>
<tr>
<td>OCTG</td>
<td>oil-country tubular goods</td>
</tr>
<tr>
<td>PMI</td>
<td>positive material identification</td>
</tr>
</tbody>
</table>
PoD probability of detection
ppm parts per million
PR Performance Requirements
PREN pitting resistance equivalent number
psia pounds per square inch absolute
psig pounds per square inch gage
PSL Product Specification Level
PT penetrant (dye) testing
PWHT post weld heat treatment
QA quality assurance
QC quality control
RT radiographic testing
RWP rated working pressure
RGD rapid gas decompression
SC API CSOEM Subcommittees
SCC stress corrosion cracking
SSC sulfide stress cracking
UT ultrasonic testing
UTS ultimate tensile strength
YS yield strength
VME von Mises equivalent stress

3.3 Symbols
For the purposes of this technical report, the following symbols shall apply.

\[ \frac{da}{dN} \] Fatigue crack growth rate
\[ (\frac{da}{dN})_{EAC} \] Fatigue crack growth rate developed in service environment
\[ \Delta K \] Stress intensity factor range
\[ J_{IC} \] Fracture toughness measured using the J-integral method per ASTM E1820
\[ K_1 \] Mode 1 stress intensity factor
\[ K_{IC} \] Material plane strain fracture toughness
\[ K_{IEAC} \] Mode 1 stress intensity factor measured in service environment
\[ in \] inch
\[ s \] time in seconds


4.1 General

Significant industry efforts were carried out for the publication of API Technical Report PER15K-1: “Protocol for Verification and Validation of HPHT Equipment” (herein API PER 15K-1), which details compilations of physical behavior of materials, expected service conditions and consequences. It took a system level approach to the review of the entire well system; from sand-face to pipeline with emphasis on environmental conditions and interface issues where one set of hardware in the well
may affect adjacent hardware, all exposed to HPHT conditions. However, API PER 15K-1 does not offer analysis tools or design processes for the verification or validation of specific hardware due to each component group, as governed by the various product SC's within API that have vastly different operating conditions, functional requirements and acceptance criteria.

In this regard, the intent of this technical report is to provide additional guidance on analysis tools and design processes to address the applications cited in API PER 15K-1 for the design verification and validation of subsea production hardware and systems.

4.2 HP Effects, HT Effects and HPHT Effects

4.2.1 HP Effects

4.2.1.1 General

The majority of oilfield equipment is designed around the frame work, definitions and formula found in API 6A (6X), which is acknowledged to be a working subset of ASME Boiler and Pressure Vessel Code (BPVC) Section VIII, Division 2: 2004 Edition (herein ASME Div. 2: 2004). For HP application, API has historical data on the limited practice of 30ksi RWP equipment with API 6AB, and the current practice of 20ksi RWP equipment with API 6A. However, these pressure rating delineations are not consistent with ASME BPVC recommending, but not requiring, that equipment designed for RWP greater than 10ksi follow the design practices of ASME BPVC Section VIII, Division 3 rather than continuing with the design practices of ASME Div. 2: 2004. Further, there were significant revisions to the subsequent editions to ASME Div. 2: 2004 (e.g., 2007 Edition and later). These issues have posed significant quandary with API 17TR8 task group.

4.2.1.2 Analytical Methods

With reference to the current ASME BPVC Section VIII, Division 2: 2013 Edition (herein ASME Div. 2) and ASME BPVC Section VIII, Division 3: 2013 Edition (herein ASME Div. 3), it should be noted that the design practices and analytical methods (e.g., linear-elastic, elastic-plastic) are similar in principles between these two codes; however, they have different design margins (ASME Div. 2 = 2.4 on UTS and ASME Div. 3 = 1.8 on UTS) and minimum hydrostatic test pressures. Both design codes utilize the analytical methods referenced therein to verify that the pressure vessel has adequate protection against typical failure modes, i.e., global plastic collapse, local strain damage limits, etc.

Additionally, ASME Div. 3 has implemented fracture mechanics (FM) analysis to address the potential fast-fracture failure of pressure vessels from material flaws and/or imperfections occurring randomly in critically stressed locations (i.e., gross structural discontinuities, notches, sharp corners, etc.). However, ASME Div. 2 references the traditional stress-cycles fatigue curves (S/N curves) to address fatigue/life-cycle estimation if the equipment is identified to be fatigue sensitive from the screening process.

4.2.1.3 “Thin-Wall” - “Thick-Wall” Designs

The transition from 15ksi to higher RWPs also hastens the change from “thin-wall” to “thick-wall” pressure vessel designs, where “thick-wall” is the result of the vessel outer radius to vessel wall thickness ratio below “4” or R / t ≤ 4). Two fundamental changes are occurring when transitioning from “thin-wall” to “thick-wall” pressure vessel designs:

1) The pressure effect referred to as “autofrettage” is a phenomenon associated with the inner-wall of the pressure vessel showing material approaching or exceeding the material’s yield strength (YS) while further way from the bore, material stress decreases well below the yield strength, and

2) The pressure vessel’s increasing susceptibility to cyclic loads leading to either a fatigue failure or a fast-fracture failure at areas of highly localized stress. This phenomenon is typically associated with stress concentrations on the inside at sharp corners, such as bore intersections, seal pockets or abrupt changes in bore diameters, as autofrettage is experienced. Cyclic loading effects on stress concentrations has been a long standing practice for fatigue failure utilizing S/N fatigue curves for predicting when and/or where materials may fail from external mechanical loads. However, the potential fatigue failure can now occur inside as well as outside from imperfections or flaws at highly stressed locations from high pressure loads or mechanical cyclic loads. Another fatigue assessment method is following the FM methodology to predict or estimate life-cycle from inherent flaws growing or propagating within the elevated stress field until the flaws grow to a point where the materials physical microstructure is compromised, resulting in a fast-fracture failure of the component’s wall.
Since its inception, API 17TR8 task group contemplated the notion of where does oilfield equipment designs change from "thin-wall" to "thick-wall"; given the service history of equipment with existing API specifications ("thin-wall" / linear-elastic analysis), or adopt and embrace a new design regimen ("thick-wall" / elastic-plastic analysis). Either way, thicker-wall designs are becoming increasingly difficult to manufacture, fabricate or handle (heavy lift) for practical applications, and difficult to maintain uniform material strength over the wall sections of manufactured equipment (through-wall properties). By easing the design margins and test pressure, designed product can be more manageable, but it comes with the trade-off of more rigorous analysis, validation and additional quality assurance.

4.2.1.4  **API 17TR8: Analysis Principles**

Traditionally, the standard practice is to rely on the ASME BPVC to provide design guidance when the equipment’s functional requirements go beyond the defined boundaries of the API specifications/standards. However, the problem then arises as to "how much of the ASME BPVC does one follow": 1) exactly to the “letter” or use portions of the code that are applicable to the particular design; or 2) following a “parallel” path using the ASME BPVC methods, but develop another set of design margins applicable to oilfield applications. Oilfield equipment are of complex geometry, far from a simple cylindrical pressure vessel or piping union design and are typically subjected to a variety of extreme external loading conditions not found nor addressed in the ASME BPVC design margin tables. This leads the equipment designer to rely on sound engineering practices/judgement, accompanied by unique validation prototype testing programs.

As a result, the API 17TR8 task group recognizes that equipment with 15ksi RWP (or lower) with HT effects should continue with the simpler, traditional linear-elastic analysis in the existing API specifications (e.g. API 6A(6X), API 17D) and within the scope of the governing standards, as this has yielded robust and field-proven designs.

For RWP greater than 15ksi to 20ksi, inclusively, there is a transitional zone where both linear-elastic and elastic-plastic design methodologies can be utilized, but with additional consideration. Traditional design practice of linear-elastic analysis can be followed with additional considerations or the more advanced, rigorous elastic-plastic design method of ASME Div. 2 can be applied for this pressure rating range. Either way, it relies on higher design margins, hydrostatic test pressures and sizable material properties to provide adequate safety margins to cover complicated or unknown loading conditions. It should be noted that this conservatism may not cover all of the autofrettage, stress concentrations and mechanical cyclic loads for more complicated geometries. Therefore, design “check-gates” has been added to alert the equipment designer when simpler design methods or geometries that are more complicated could mask a less stable design.

For RWP greater than 20ksi, the more rigorous elastic-plastic design methodology of ASME Div. 3 should be used, and as such, can "ease-up" on design margins and hydrostatic test pressures. However, it is necessary to also tighten the allowable range and more accurate material model/properties (true-stress/true strain) to stay within the lower design margins. In addition, “thick-wall” design methods perform more investigative analysis at stress concentration “hot-spots” to assess the possibilities of fatigue or fast-fracture using FM analysis. Cyclic loading automatically becomes a part of design regimen, not just a consideration.

In summary, there are three (3) analytical design paths that can be applied to HPHT designs:

1) For 15ksi RWP with HT effects, the traditional or existing linear-elastic analysis in API 6A(6X) is appropriate;

2) For RWP greater than 15ksi to 20ksi, inclusively, recommended design practices of ASME Div. 2 through linear-elastic analysis (with additional consideration) or elastic-plastic analysis should be used, due to the more inclusive nature to accurately assess pressure and mechanically induced cyclic loading, along with its more lenient design margins to arrive at practical solutions; and

3) For RWP greater than 20ksi, the elastic-plastic design methodology of ASME Div. 3 is required, as the internal bore yielding effect becomes more pronounced and the design margins (associated with thin-wall/linear-elastic analysis) may not cover some unknown factors.

Detailed guidance on the appropriate applications of these design analysis methodologies are provided in Section 5 of this technical report. Additionally, Section 6 of this technical report provides guidance on the material properties and material models associated with these design analysis methodologies.

4.2.2  **HT Effects**

4.2.2.1  **General**
The HT effects on materials in HPHT application is qualitatively understood, however, lesser quantitatively. Increased temperature gradually reduces the metal’s yield and tensile strength, usually as a linear function of temperature. However, a material’s other properties are far less published or understood.

4.2.2.2 HT Effects on Material Properties

HP designs are feasibly scalable as the pressure increases as mechanical load may be examined with scaled prototypes and stand-in materials. Moving mechanisms with clearance gaps and tolerances can be modelled and exercised in attesting lab at room (ambient) temperature to learn of its performance limits.

Working at elevated temperatures or HT application introduces a whole new set of variables in equipment designs. Different materials adjacent to each other may be functionally suited for each part, but each component in the assembly could expand or contract at different coefficients of expansion and Poisson’s ratio, changing the geometry of seal pockets, glands, sliding clearances, etc. This effectively defeats the mechanism at elevated temperatures that otherwise work well at lower temperatures. Additionally, elevated temperature in corrosive environments is also relatively unknown.

Most available data on material compatibility in severe environments is at room temperature conditions. However, elevated temperature will most likely accelerate the corrosive conditions, changing the corrosion rates or susceptibility to microstructure attack by adding more energy to the chemical and atomic forces at work. Elevated temperature will also change the material’s fracture toughness values (i.e., \( K_{IC}, \Delta K \), etc.), thus changing the expected cyclic life of a component. More is known about fracture toughness data at room temperature and cold (arctic) temperatures, but little data is available at elevated operating temperatures, especially for oilfield equipment. These values will most likely be further eroded by severe environments.

The main concern is the availability of material data. Some material properties may be inferred from data published for aerospace and nuclear applications where the operating temperatures are either significantly higher or lower than the typical temperature defined for HPHT environment, and it is often not the “exact” material grade. Additionally, oilfield environments are far more active and corrosive than the other industries, making data interpolation less plausible. In this regard, this technical report provides detailed guidance on the types of material data/properties required for the design analysis at the required temperature class and with consideration to the environmental effects on the material properties (Refer to Section 6).

4.2.2.3 HT Effects on Seals and Fasteners

Sealing materials against the part geometry is another significant consideration with HT effects. Selection of seal material is a function of its own geometry and includes degree of pliability during assembly (or removal), longevity at temperature (ambient or elevated/operating) and resiliency to repeat cyclic expansion/contraction of surrounding parts. Non-metallic seals have an additional concern with respect to temperature limits changing its chemistry, molecular make-up or its physical properties. Non-metallic components are often tested at elevated temperatures to discern a compound’s operating life through accelerated aging tests (e.g. API 6TRJ1 or NORSOK M-710). Elastomers typically peak at 280°F (138°C) and thermoplastics peak around 400°F (200°C) for nominal design life. Higher temperatures are possible, but at a far less design/operating life. Metal seals may be the only solution available for higher operating temperatures for extended periods.

Additionally, the less pliable seal material, the harder it becomes to assemble and maintain; often requiring a completely different seal and seal pocket configuration. Less pliability also leads to tighter tolerances between parts and smoother surface finishes. Less pliable materials may also lead to less forgiveness to imperfections and dirt/debris, causing premature seal leakage or failure. Some less pliable seals may also require more elaborate sets of components to build around the seal to create the seal pocket. This added set of geometries may require additional length or width in assembled parts, resulting in greater stack-up heights in assembled hardware. As a result, a proven high-pressure design may easily achievable at lower temperatures, but may require a whole new design for each added temperature regime, making scaling for size and different temperatures (for the same rated working pressure) difficult to achieve.

Seals also have a specific problem with temperature range. If the temperature range is kept fairly narrow, parts do not expand or contract nearly as much and the overall seal configuration remains fairly constant. As the range widens, less pliable materials need to be used for the upper end of the temperature range, but become too rigid and stiff at the lower end. This often causes seal leakage at other one end of temperature extreme. Furthermore, seal pocket geometry and tolerance (extrusion) gaps get wider or narrower, encouraging seal extrusion or pinching off (often called nibbling), damaging the seal and lead to premature failure. The wider temperature range could also encourage material fretting in metal seals due to the added movement between seal and seal pocket surfaces.

A more subtle concern is stress relaxation, as observed by research conducted by Larson-Miller and Orr-Sherby-Dorn. They observed that highly stressed components at elevated temperature will experience a gradual redistribution of the component over time in a manner that lowers the residual stress in the part (similar to performing post weld heat treatment process on
weldments to allow the part to relieve some of the induced stress caused by welding and subsequent cooling). In pressure-containing and pressure-controlling components, this is not of significance. However, for seals and fasteners, an eventual change of a few thousandths of an inch or a loss of preload force may lead to a seal degradation or reduction in connection forces. Therefore, material testing standards for stress relaxation are addressed in this technical report to help define seal and fastener material requirements (Refer to Section 6 and Section 7).

4.2.3 Combined HPHT Effects

Temperature effect is the obvious "wildcard" when combining HP and HT application. Pressure is a function of geometry and material properties, but when temperature can change all material properties and geometries, additional degrees of freedom need to be addressed for each pressure and temperature combination. As mentioned above, any change in the form-fit or function may change the design and may require a new set of validation tests for every combination.

As indicated above, a change in material selection may change the way a seal pocket assembly is configured which could result in a need for additional space and hence a larger stack-up in the assembly for the same size and rated working pressure. Multiple seals or multiple connection points (each can potentially be larger) exacerbates the overall assembly size and configuration, in addition to added material costs, weight and assembly complexity. The industry has had success in developing HP equipment at lower standard temperatures, below 350°F (177°C). The same can be shown for HT equipment at relatively low-pressure ratings (below 3ksi), but every HPHT permutation tends to create a unique design; exacerbated when a wide temperature range (high and low) is added to the functional requirements.

4.3 Loading Conditions – What is Unique to Subsea?

In addition to the HP/HT effects on equipment, the subsea environment poses several unique challenges to HPHT equipment designs, as related to loading conditions, including:

1) The subsea/ocean environment:
   a) External hydrostatic pressure: when, where and how to appropriately apply.
   b) Constant cold temperature:
      1) Massive heat sink
      2) Widens the temperature range
      3) Selective use to augment material properties: when and where to use it.
   c) Sea-water corrosion and CP effects on material properties

2) External loads:
   a) Thermal and pressure expansion and contraction
   b) Cyclic loads imposed by intervention vessels
   c) Cyclic loads imposed by metocean environment

3) Flow assurance considerations:
   a) Appropriate insulation to minimize heat sinks
   b) Appropriate insulation for achieve a temperature rating

4) Remoteness:
   a) Remote monitoring versus restricted service life
   b) Running tool inspection and refurbishment
In this regard, the equipment functional specifications and basis of design should take into consideration the loading conditions as indicated above, as applicable (Refer to Section 5.2).

5. Design Verification

5.1 General

The objective for design verification is to confirm that the HPHT equipment design is in compliance with its functional specifications and the equipment has adequate protection against failure modes identified for HPHT equipment, including:

1) Global plastic collapse;
2) Local failure due to excessive strain (local strain limit damage);
3) Ratcheting effects;
4) Plastic collapse under the hydrostatic test condition; and
5) Fatigue (life-cycle estimation).

The loads obtained from the functional specifications forms the design basis for the HPHT equipment, and should include all applicable operating pressure, temperature, and external loads as well as the corresponding cyclic loadings (loading histogram) for all significant events that are applied to the equipment.

It is necessary that users of this technical report be aware of regulations of a jurisdictional authority that may impose additional or different requirements which better suit the demands of a particular service environment. Where API product standards exist with specific design factors for HPHT equipment, these factors should be met as a minimum, unless this technical report directly or by reference provides other design factors.

In this regard, Figure 5.1: HPHT Design Flow Chart provides detailed processes for the design verification, including design validation, for HPHT equipment that requires the equipment designer to:

1) Identify the scope of the equipment for appropriate application of design verification path (Refer to Section 5.1)
2) Define the input parameters for design analysis (Refer to Section 5.2)
3) Perform the design analysis (Refer to Section 5.3)
4) Perform the fatigue assessment / life-cycle estimation, as necessary (Refer to Section 5.4)
5) Perform the design validation (Refer to Section 8)

Detailed procedures for these design flow chart processes are provided in the following sections of this technical report.

5.2 Scope of HPHT Design Flow Chart

5.2.1 General

Use of Figure 5.1 is based on one or a combination of conditions indicated in Section 1, and depicts the equipment design and temperature rating criteria for HPHT application.

The HPHT Design Flow Chart is intended for pressure-containing components. The design methodology referenced therein may also be applied to pressure-controlling components, if the design methodology can assess the failure mode. However, failure mode for pressure-controlling components is typically identified as deflection and/or leakage. For pressure-controlling components, the applicable design standards remain the governing requirements.

Figure 5.1 provides several analytical paths for the design verification of HPHT equipment for protection against identified failure modes. Each respective path initiates by addressing the required design input parameters, the existing API
Figure 5.1: HPHT Design Flow Chart

Notes:
1. Maximum temperature = 550°F
2. Refer to Section 5.3-2
3. Refer to Section 5.4.1
   - Based on ASME Div. 2 Section 5.5.2 or equipment’s functional specifications

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specifications, with progression to incorporate the design practices provided in ASME Div. 2 or ASME Div. 3. Considerations are given to the following:

1) Existing API specifications, e.g. API 6A (6X), API 17D;

2) Additional requirement for “thick-wall” equipment analyzed with linear-elastic analysis of ASME Div. 2;

3) Recognition of advancements in design analysis methodology of elastic-plastic analysis of ASME Div. 2 and ASME Div. 3;

4) Fatigue-screening to determine the requirements to perform fatigue assessment; and

5) Fatigue assessment (life-cycle estimation).

The analytical method traditionally used in current API product specifications (e.g., API 6A, 17D) is based upon the design practices of ASME BPVC Div. 2, 2004 Edition Appendix 4, applying linear-elastic analysis with design margin defined per the material’s yield strength. These existing industry practices have resulted in successful, field proven equipment. However, the increased design pressures and design temperatures defined for HPHT applications will result in higher stresses and strains for pressure-containing components or the use of thicker-wall components, which may require additional assessment and/or advanced methodology for accuracy.

The HPHT Design Flow Chart permits the use of API 6A (6X) design verification methodology for equipment with pressure rating of 20ksi or lower, and within the scope of the applicable governing design standards. However, caution should be taken that the API 6A (6X) methodology should take into consideration all applicable service conditions (e.g., subsea application), where external loading is more prevalent than surface applications for which API 6A was developed. To ensure the equipment is fit for intended service, the equipment designer may need to utilize the linear-elastic analysis of ASME Div. 2, or elastic-plastic analysis of ASME Div. 2 with progression to ASME Div. 3, as necessary.

While selective application of various API and ASME design practices can provide equivalent levels of safety, design of HPHT complex “thick-wall”, pressure-containing components requires analysis methods for structural and functional integrity to comply with design life-cycle requirements with proper safety margins. Additionally, the material properties and nondestructive examination (NDE) must be defined in such a manner that they are accurately defined in the structural and failure assessments. Utilizing thicker-wall equipment for HPHT application will result in some technical challenges (e.g. additional weight, uncertainty in through-wall material properties for “thick-wall” equipment, additional manufacturing considerations, and optimization of the design to ensure integrity). “Thick-wall” equipment may also impact the equipment-supporting infrastructure requirements, i.e., handling, lifting, supports, etc. Additionally, HPHT equipment may exhibit additional failure modes (e.g., cyclic loadings, ratcheting, or brittle fracture) in which characteristics must be addressed through advanced design methodology.

Therefore, advanced analytical techniques utilizing finite element analysis (FEA) methods, linear-elastic and elastic-plastic evaluations of ASME Div. 2 or ASME Div. 3 should be considered in HPHT equipment design, along with more advanced material testing, NDE inspection and acceptance criteria. Application of these techniques will provide an accurate prediction of material stress and strain conditions, which can be used for verification of the design for both structural and functional capacities. Those evaluations provide a more thorough understanding of the material’s behavior in the plastic zone and, provide a more accurate assessment of the HPHT equipment against its mechanical integrity and life cycle requirements.

Subsequent to the design verification for pressure containment integrity, equipment that may undergo cyclic operations (i.e., pressure, temperature, external loads, etc.) should be subjected to a fatigue assessment to calculate its life-cycle characteristics for compliance with the functional specifications (Note: further discussion on Fatigue Assessment is provided in Section 5.4). Evaluation of the pressure-containing component using the fatigue screening methods of this technical report will determine if fatigue analysis is required. If fatigue analysis is not required based on the screening criteria, this must be documented within the manufacturer’s technical specifications with technical justification. Results of a fatigue screening and/or assessment may indicate more rigorous evaluation is required using the design practices involving the S/N fatigue curves (S/N approach), fracture mechanics (FM approach), and fatigue crack growth rate (FCGR), as defined in ASME Div. 3, API 579-1/ASME FFS-1 or BS 7910.

5.2.2 Recommended Path for Design Verification

Operators/manufacturers of HPHT equipment may initiate the design verification process by following the traditional design practices of linear-elastic analysis per API 6A (6X) or ASME Div. 2, as applicable. This approach has historically been
relative straight-forward for equipment pressure rating of 20ksi or less, yielding robust designs that can satisfy functional specifications and life-cycle requirements with limited need for post-manufacture or “in-service” re-evaluation.

The HPHT Design Flow Chart introduces the application of linear-elastic analysis in accordance with ASME Div. 2. Although the linear-analysis methodologies of API 6A (6X) and ASME Div. 2 are similar, consideration to the loading conditions (i.e., external loads, combined loads, etc.) vary between these standards. Therefore, the designer should address all loading conditions as specified in the equipment’s functional specifications through the appropriate selection of these referenced design standards. Additional requirements for using linear-elastic analysis of ASME Div. 2 for HPHT equipment are specified in Section 5.3-2 of this technical report to verify protection against local strain failure mode.

Additionally, for pressure rating of greater than 20ksi, the equipment designer is recommended to use the more advance elastic-plastic analysis of ASME Div. 2 or ASME Div. 3 for benefits as stated previously.

5.2.3 Alternate Path for Design Verification

The HPHT Design Flow Chart offers an alternate direct path to the use of ASME Div. 3 design practices for HPHT equipment, with elastic-plastic analysis and FM approach for cyclic fatigue analyses. Additionally, it is the intention of this technical report that ASME Div. 3 be applied for HPHT equipment with pressure ratings greater than 20ksi.

Operators/manufacturers of HPHT equipment may choose to go directly to the design practices of ASME Div. 3 to capture potential benefits listed above related to weight, uncertainty in through-wall material properties, and optimization of design integrity, or simply to acquire a more thorough understanding of the material’s behavior in its plastic zone and a more accurate assessment of the HPHT equipment characteristics against its mechanical integrity and life-cycle requirements.

While the use of ASME Div. 3 design practices for HPHT equipment designs can offer certain advantages (e.g., carries a lower design margin than the design practices of ASME Div. 2), it may also necessitate more rigorous constraints on static and cyclic loading identifications, material testing and inspection, manufacturing, and life-cycle load monitoring to confirm that predicted cyclic loading conditions have not been exceeded. Operators/manufacturers who elect to go directly to the design practices of ASME Div. 3 for design verification should clearly identify and value-assess the benefits, constraints, and life-cycle/load monitoring requirements typically associated with the direct ASME Div. 3 approach.

5.3 Define Input Parameters for Design Analysis

5.3.1 Functional Specifications

The design verification process starts with the equipment’s functional specifications. The equipment user/or operator should provide a complete functional specification as the basis of design for the equipment using a life-cycle approach with sufficient details for the manufacturer to conduct the design analysis or design verification in accordance with HPHT Design Flow Chart and the guidelines of this technical report.

The functional specifications should include, but not be limited to, the following:

1) Well pressure and temperature (bottom hole and at wellhead during flowing conditions) over the life of the well
2) Well fluid properties or compositions (i.e., H₂S, CO₂, etc.)
3) Pressure integrity
4) Mechanical / structural loads
5) Environmental and/or metocean conditions
6) Cyclic loading / life-cycle requirements (i.e., pressure cycles, temperature cycles, external loads, etc.)
7) Corrosion, corrosion/erosion requirements
8) Specified loads and characteristics including temporary test conditions, possible cyclic loading conditions and changes to those parameters over the operating life, thermal gradients, external loadings, etc.
9) Storage / transport conditions

10) Applicable industry standards and/or regulatory requirements

Guidance on developing a functional specification can be found in ISO 13879. API PER 15K-1 provides additional guidance on elements of the functional specifications. API PER 15K-1 also provides guidance on HPHT equipment service criteria.

5.3.2 Failure Modes, Effects and Criticality Analysis

A FMECA should be performed at an early stage of the design process. When performed in the early design phase, a FMECA can assist in mitigating any identified risks where modifications to the design are feasible options. The FMECA analysis should be performed by the equipment user and manufacturer. FMECA is an extension of an FMEA (failure modes and effects analysis) process where a criticality assessment, "C", is identified or assigned to the component. The basis for the FMECA process should be derived from the equipment’s functional specifications.

A FMECA should be performed to identify all possible failure modes, resulting hazards affecting the component/sub-system/system, and the component’s criticality to a complete sub-system or system. API PER 15K-1 provides additional guidance on the FMEA process and API 17N provides guidance on the FMECA process.

An additional objective of the FMECA analysis, in the context of this technical report, is to identify any additional validation testing requirements associated with the equipment’s Performance Requirements (PR) based on identified failure mode(s) or event(s), as applicable. This technical report presents PR3 and PR4, as indicated in Figure 5.1. The definitions and the design validation considerations for PR3 and PR4 are provided in Section 8 of this technical report.

5.3.3 Material Properties

Material properties (i.e., yield strength, tensile strength, modulus of elasticity, etc.), and fatigue properties (i.e., S/N fatigue curves, FCGR, etc.) should be identified and/or generated in accordance with the temperature and environmental parameters specified in the equipment's functional specifications, and utilize as input parameters to the design analysis of HPHT equipment.

Section 6 of this technical report provides detailed guidance on the material requirements for HPHT application. General guidance on material selections is provided in Annex B, Material Selection. Additional guidance on material quality control (QC) is provided in Annex C, Material Quality Control.

5.3.4 Product Specification Level

The Product Specification Levels (PSL) provides varying levels of quality control and assurance related to material quality and properties. PSL levels for HPHT equipment are based on their governing API 6A/17D product standards (e.g., PSL3 and PSL4), and they are associated with the current API 6A (6X) and ASME Div. 2 design practices, as indicated in Figure 5.1.

The design flow chart introduces PSL5, where is it applied to ASME Div. 3 design practices. It should be noted that additional assurance process to ensure material quality and properties for PSL5 may include, but not be limited to, the following:

1) Material testing and specimen locations
2) Fracture toughness (FT) properties
3) Charpy toughness values
4) Limits on ovality and misalignment
5) Extent of NDE as QC
6) NDE capability for flaw detection

These additional assurance processes are applicable to PSL5, in addition to the requirements of PSL3/PSL4. Guidance on the specifics of the above parameters is provided Section 6 of this technical report and applicable parts of ASME Div. 3.
5.4 Design Analysis

5.4.1 General

For the design analysis of HPHT equipment in accordance with Figure 5.1, this technical report provides the following provisions to be applied for the design verifications:

1) Design by Analysis: This technical report recommends that design-by-analysis through FEA be used. FEA methodologies associated with design verification should be 1) linear-elastic or 2) elastic-plastic analysis. These design verification methodologies are appropriately identified in Figure 5.1 to their respective applications. Section 6 of this technical report advises on the material models and material properties required for these design analysis methodologies.

2) Linear-Elastic Analysis Applied for “Thick-Wall” Equipment: The traditional application of linear-elastic analysis (per ASME Div. 2) may result in non-conservative designs from the stress classification procedures (Refer to ASME Hopper diagrams of ASME Div. 2 or ASME Div. 3) to demonstrate structural integrity for “thick-wall” (R/t ≤ 4) pressure-containing components, especially around gross structural discontinuities, or notches. This is due to variations in the stress distribution within the wall thickness.

In this regard, linear-elastic analysis may be used for the design analysis of “thick-wall” pressure-containing equipment, in addition to the requirements specified in Figure 5.1, when the von Mises equivalent stress (VME) does not exceed the material’s yield strength through more than 5% of component thickness in the worst case loading scenario/combinations, including the hydrostatic pressure test load case. Additionally, mesh sensitivity analysis should be performed to validate the FEA analysis and ensure that the mesh density variations do not affect the stress distribution (within 5% variance) through the component thickness.

3) Stress Components: The calculated stress components derived from the FEA analysis should be combined using the VME failure theory instead of the maximum shear stress theory or stress intensity (S_{int}). The VME stress failure theory is a more accurate predictor for the onset of yielding in ductile materials. Current API specifications utilize the S_{int} theory while ASME Div. 2 and ASME Div. 3 use the VME stress theory.

4) Load Resistance Factor Design (LRFD): In addition to the current API specifications, the HPHT Design Flow Chart specifies ASME Div. 2 and ASME Div. 3 as design practices for HPHT equipment designs. Within these design standards, ASME specifies the Load Resistance Factor Design (LRFD) analysis method, which is considered one of the more accurate analysis methods. This method requires design-by-analysis, such as FEA, with applied “load factors” or design margins to verify that a pressure-containment equipment design has adequate margin as protection against the identified failure modes (e.g. plastic collapse, rupture).

It should be noted that there are differences in the specified load factors or design margins between ASME Div. 2 (2.4 on UTS) and ASME Div. 3 (1.8 on UTS). ASME Div. 3 cites a lower design margin, which would be beneficial to maintain high-pressure equipment with reasonable wall thickness. However, the lower design margin requires additional considerations by the equipment designers or operators, i.e., material properties, toughness (ductility), NDE, QC, etc., (Refer to Section 5.1.2), as compared to the higher design margin of ASME Div. 2. An additional loading consideration for oilfield equipment is the load bearing interface between components within an assembly. This loading consideration can be applied as an equivalent pressure end load, as applicable.

5) Load Descriptions: Table 5.2 and Table KD-230.2 of ASME Div. 2 and ASME Div. 3, respectively, provide a description of the loads which are analyzed using these codes. These loads may not directly correspond to the loadings required to be analyzed for equipment of API 17D. The following is a proposed correlation between API loads and ASME defined loads. The defined loads do not identify all loading cases, but provide guidance on load categorization between ASME and API requirements:

\[ P = \text{Internal or external, specified design pressure} \]
\[ P_T = \text{Hydrostatic test pressure} \]
\[ D = \text{Suspension or external loads, i.e., casing loads, external riser or piping loads, installation loads (running), wave and current loading, vortex induced vibration (VIV), etc.} \]
\[ L = \text{Fluid dynamic loading, i.e., slugging, water hammer, flow induced vibration, etc.} \]
\[ T = \text{Self-restraining loads, thermal expansions, installation misalignment loads or preloads.} \]
With consideration to the above, the following sections outline the design analysis process in accordance with the HPHT Design Flow Chart to verify protection against the identified failure modes for HPHT equipment.

### 5.4.2 Protection against Global Plastic Collapse

The design verification for protection against plastic collapse can be accomplished through linear-elastic analysis, where permitted by Section 5.3-2, or elastic-plastic analysis.

1) **Linear-Elastic Analysis:** Current API 6A (6X), API 17D, and applicable sections of ASME Div. 2 specify linear-elastic analysis for global plastic collapse load. Nevertheless, the equipment designer is cautioned to ensure appropriate utilization of the linear-elastic analysis methodology, as this approach has the potential for non-conservative results from "thick-wall" stress distribution theory, and/or stress categorization difficulties due to complex geometry associated with HPHT equipment. Compliance with Section 5.3-2 of this technical report is required when linear-elastic methodology is utilized for "thick-wall" (R / t ≤ 4) pressure-containing equipment analysis.

2) **Elastic-Plastic Analysis:** Elastic-plastic analysis provides better accuracy in the assessment of protection against global plastic collapse of a component relative to the linear-elastic analysis method, as the elastic-plastic stress analysis simulates the component's actual material behavior under the applied loadings. The maximum allowable working load is calculated by applying the applicable design factor to the internal or external pressure, hydrostatic head loads and dead weight loads to verify that these loads do not exceed the component’s plastic collapse load (load at which unbounded plastic deformation occurs). The elastic-plastic analysis, with the applicable design factor, is to be performed in accordance with the global criteria of the applicable sections of ASME Div. 2 or ASME Div. 3, as referenced in Figure 5.1.

Subsequent post-processing of FEA results can be retrieved for the verifications of other applicable failure modes, i.e., local strain limit damage, ratcheting effects, fatigue, etc. The material properties used for these analyses are to be in accordance with Section 6 of this technical report.

### 5.4.3 Local Strain Limit

In addition to demonstrating protection against global plastic collapse, the applicable local strain limit failure criteria should be satisfied for HPHT equipment design. Areas of gross structural discontinuities are typical locations for high-stress risers (peak stress/strain) which may cause local plastic strain and potential initiation site for fatigue or crack initiation. Linear-elastic or elastic-plastic stress analysis method can be used for local stress or strain assessment.

1) **Linear-Elastic Analysis:** The linear-elastic analysis criteria to prevent local failure at peak strain locations, (i.e., gross structural discontinuities, notches, etc.) within the pressure-containing equipment is defined in the applicable section of ASME Div. 2. Alternatively, the triaxial-stress criteria of ASME Div. 3 Article KD-249 can be used to verify the local strain limit criteria.

2) **Elastic-Plastic Analysis:** The elastic-plastic analysis is used to define a limiting triaxial-strain at peak strain locations (i.e., gross structural discontinuities, notches, etc.) within the pressure-containing equipment. If FEA analysis determines that the localized strain on a component exceeds 5% to a depth exceeding the critical crack depth then it is recommended that the environment assisted cracking evaluation is conducted on the material in a similarly strained condition. The local strain analysis should be performed in accordance with the applicable sections of ASME Div. 2 or ASME Div. 3, as referenced in Figure 5.1.

### 5.4.4 Ratcheting Effects

Protection against ratcheting (e.g., the repeated application, removal, and re-application of load that results in unsustainable stress-strain hysteresis) can be analyzed using either linear-elastic or elastic-plastic analysis as defined in Figure 5.1.

1) **Linear-Elastic Analysis:** The linear-elastic analysis criteria to prevent ratcheting through the thickness of the pressure-containing component are defined in ASME Div. 2 Section 5.5.6.

2) **Elastic-Plastic Analysis:** Elastic-plastic stress analysis can be used to ensure the pressure vessel does not fail by ratcheting. The elastic-perfectly plastic material properties used for this analysis should be input at the material minimum specified yield strength. The ratcheting assessment should be performed in accordance with the applicable sections of ASME Div. 2, or ASME Div. 3, as referenced in Figure 5.1.

### 5.4.5 Protection against Plastic Collapse under Hydrostatic Test Condition

...
Linear-elastic or elastic-plastic analysis can be used to ensure the pressure-containing equipment does not exhibit plastic collapse under the hydrostatic test pressure specified in Figure 5.1. The hydrostatic test condition stress analysis should be performed in accordance with the applicable sections of API 6A/17D, ASME Div. 2 or ASME Div. 3. Equipment rated for pressures up to and including 20ksi maximum rated working pressure should follow the guidelines of API 6A/17D for hydrostatic testing. Additional guidance on hydrostatic test procedures is provided in Section 9 of this technical report.

5.5 Fatigue Assessment / Life-Cycle Estimation

5.5.1 General

Subsequent to the design verification for pressure containment integrity, HPHT equipment that may undergo cyclic operations (i.e., pressure, temperature, external loads, etc.) should be subjected to a fatigue assessment to calculate its life-cycle estimation for compliance with its functional specifications. Appropriate fatigue screening processes can be applied to determine if the HPHT is fatigue-sensitive or fatigue limited.

There are two (2) methods of evaluating fatigue or life-cycle assessment:

1) S/N approach with alternating stress or strain amplitude, or

2) FM approach based on material’s fatigue crack growth data, da/dN vs. ∆K, with alternating stress cycles which result in an alternating crack tip stress intensity.

Each method requires a detailed component or system level load histogram as input with appropriate material properties defined for the design verification. The S/N approach and the FM approach are defined in this technical report with guidance on appropriate applications.

Failure assessment due to fatigue cycling should be based on an effective alternating stress or alternating strain for a given number of cycles based on detailed load histograms accurately defined between the manufacturer and operator as well as operating environments design life, and inspection intervals, as applicable. The number of cycles should be adequate to satisfy the operator/user defined cycle life or functional specifications. The fatigue cycles should include all cyclic loadings for the life of the component, which includes factory testing, installation loadings, and operational loads.

The fatigue assessment must identify the most highly stressed regions that are the most critical for fatigue crack initiation and/or fatigue crack propagation/growth. When the FM approach is used, the alternating stresses defining the path of crack growth should be based on the maximum principal stress range. The crack is assumed to propagate in a plane perpendicular to the direction of the maximum principal stress. It should be noted that fatigue crack growth is load path dependent. Evaluation of load sequence to determine the load combinations which result in the least number of cycles to failure should be considered.

Where life-cycle estimation represents the number of load cycles to failure, based on S/N approach, the equipment designer is to ensure that the calculated fatigue life is at a minimum three (3) times the service life for all components considered accessible for inspection during its service life. For components that cannot be inspected, the equipment designer is to ensure that the calculated fatigue life is at a minimum ten (10) times the service life. For FM approach, the allowable cycles for the intended service life should be based on the critical flaw size, as specified in Section 5.4.2-2(c) below.

5.5.2 Fatigue Screening

Fatigue screening is a process to determine if the HPHT equipment is fatigue sensitive, where a detailed fatigue assessment is required as part of the design verifications. The provisions of ASME Div. 2 Section 5.5.2 can be used as the fatigue screening process, based on the full-range pressure/temperature cycles and operating pressure/temperature cycles ranges, as applicable. Additionally, successful operational historical data of similar equipment can be used as the basis for fatigue screening. Fatigue screening should be evaluated based on a detailed load histogram which must be defined as part of the functional specifications.

5.5.3 Fatigue Assessment

If the HPHT equipment does not satisfy the fatigue screening criteria as referenced in Section 5.4.1 of this technical report, a detailed fatigue assessment through the S/N or FM approach should be performed. Specific to the ASME Div. 3 path in Figure 5.1, the decision-gate on the application of the S/N or FM approach can be based on; 1) the leak-before-burst (LBB) criteria of
ASME Div. 3 Article KD-141, where the K_{1C} value may be based at the environmental conditions, as specified in the equipment’s functional specifications, or 2) the equipment intended service/functional specifications.

1) S/N Approach: Equipment subjected to cyclic loading that does not meet the fatigue screening criteria should be evaluated for life-cycle estimation by the S/N approach in accordance with ASME Div. 2 Section 5.5 or ASME Div. 3 Article KD-3, if the LBB criteria are met. Fatigue-sensitive locations (i.e. gross structural discontinuities, notches, etc.) should be identified and fatigue analyses performed on these locations. The result of the fatigue analysis will be a calculated number of design cycles, Nf, for each type of operating cycle, and a calculated cumulative effect number of design cycles when more than one type of operating cycle exists. Section 6 of this technical report provides guidance on establishing the S/N fatigue curves required for this approach or DNV-RP-C203 for available S/N curves associated with structural loadings.

2) FM Approach: The LBB criteria of ASME Div. 3 Article KD-141 can be used to determine whether S/N or FM approach is applicable for the fatigue assessment under the ASME Div. 3 design practice path. If the HPHT equipment cannot comply with the LBB criteria of ASME Div. 3 or the conventional life-estimation through the S/N approach, the equipment should be evaluated for life-cycle estimation through the FM approach of ASME Div. 3 Article KD-4. API 579-1/ASME FFS-1, Part 9 and Annex F or BS 7910. Section 6 of this technical report provides guidance on material properties required for the FM approach. Additionally, the FM approach requires the equipment designer also consider the following critical elements:

a) Fatigue crack growth data: When possible, fatigue crack growth data should be evaluated from test results in the intended environment since this can greatly affect the fatigue crack growth rate. Cyclic fatigue crack growth data, da/dN vs. ΔK, including threshold K_{th} and environmentally assisted fracture toughness K_{EAC}, may be determined by testing or by data that is determined to be as conservative as or more conservative than the actual material properties in the defined environment and loading conditions. Cyclic fatigue crack growth material properties for FM approach are defined in API 579-1/ASME FFS-1, Annex F or BS 7910. Additional guidance for fatigue crack growth data is provided in Section 6.4 of this technical report.

b) NDE capability: The equipment designer should define the initial flaw size based on the NDE acceptance criteria for the component with consideration to the NDE capability of the selected method. The defined initial flaw size is critical in calculating the cyclic fatigue crack growth. The flaw must be defined in both the length and width or depth directions. Typically, internal surface breaking flaws are the most critical in limiting the fatigue life and thus require length and depth dimensions. The NDE methods, capabilities and probability of detection (PoD) must define the acceptance criteria of each parameter. Sizing of flaws may require multiple NDE methods to get the complete geometry, orientation and location. Each of these parameters is a required input for the cyclic fatigue crack growth evaluation. The NDE methods defined in ASME Div. 2 Part 7 or ASME Div. 3 Part KE should be used to define the starting flaw size. Additional guidance for NDE is provided in Section 6.6 of this technical report.

c) Critical flaw size: The allowable fatigue cycle life for a surface breaking flaw propagating through the thickness should be equal to or less than 50% of the total fatigue cycles to failure.

d) Multiple flaws: The cyclic fatigue crack growth must define the acceptance criteria for multiple flaws. The cyclic fatigue crack growth analyses must show the flaws are spaced sufficiently for non-interaction over the life of the component or must be based on multiple flaws combined. Methods of defining flaw geometry, of combining multiple flaws and multiple flaw interaction are provided in API 579-1/ASME FFS-1, Part 9 or BS 7910.

e) Load monitoring / “In-Service” inspection: Components/equipment which requires periodic “in-service” inspection to evaluate according to ASME Div. 3, Appendix B. Additionally, components/equipment subjected to “in-service” inspection should have a defined service life adjustment after inspection according to ASME Div. 3, Appendix B. Additional guidance on load monitoring is provided in Annex A of this technical report.

Where “in-service” inspection is not an option available to the user/operator for verification of material degradation or behavior, a load monitoring scheme may be implemented in order to provide means to verify the operating conditions against the design parameters utilized in the fatigue assessment. The applicable parameters required to be monitored should be derived from the fatigue assessment process. Typically, these would be the operating pressure, temperature, and external loads. Additionally, load monitoring may also be implemented for the S/N fatigue assessment, if necessary.
5.6 Ancillary Systems and Components

5.6.1 HPHT Piping Systems

5.6.1.1 General

Design codes typically used in subsea piping systems (i.e., manifolds, jumpers, flowlines, etc.) are ASME B31.3, ASME B31.4, ASME B31.8, DNV RP-F112, or API RP 1111. The selection of design code or combination thereof for subsea application should be made with 1) the objective of compliance to the functional specifications and the loading conditions referenced therein, 2) protection against applicable failure modes, and 3) sound engineering judgement on applicability the selected design code.

Additionally, ASME Div. 2 or ASME Div. 3 may be utilized for additional design considerations in designing of piping components associated with the piping systems, and therefore, these ASME design practices should be applied consistent with the HPHT applications and as defined in Section 5 of this technical report. Further, if the selected design code has a high-pressure section, it should be applied for the HP applications. If the selected design code has a subsea section, it should be applied for subsea applications.

Due to the potential of stress risers that can affect the fatigue life, the calculated maximum/minimum piping ovality should comply with the limits as referenced in the selected design code. Further, misalignment of pipe bores and joints should also comply with the limits of the selected design code or equivalent.

Seam-welded pipes, longitudinal or spiral, and age-hardenable (or work-hardened) materials should not be used for HPHT applications.

5.6.1.2 Pipe Wall Thickness

Piping wall thickness calculations should be based on thick-wall formulae for HPHT applications. The required piping wall thickness should be based on the calculated minimum required wall thickness, performed in accordance with the selected piping codes, and should take an additional mill tolerance into consideration as per the referenced piping specification for nominal wall thickness.

5.6.1.3 Fatigue Assessment / Life-Cycle Estimation

The fatigue assessment of Section 5.4 of this technical report should be performed on the HPHT piping systems. If the HPHT piping system is fatigue sensitive, the design fatigue life-cycle can be calculated by the Palmgren-Miner (S/N) method, DNV-RP-D101 or DNV-RP-C203, as applicable. The acceptance criteria for the calculated fatigue-life should meet the requirements of Section 5.4.

5.6.1.4 Hydrostatic Test Pressure

The piping systems should be pressure tested to same value as prescribed by the selected piping code or the test pressure defined in Figure 5.1 and Section 9 of this technical report. Minimum test pressure should be 1.25 times the RWP without allowances for external hydrostatic pressure.

5.6.2 Closure Bolting and Critical Bolting

Closure bolting and critical bolting should be designed using the design verification requirements of API 17D. Bolt preload requirements should follow the guidelines of API 17D. Qualification, production and documentation of alloy and carbon steel bolting should meet the requirements of API 20E.

5.7 Manufacturer’s Technical Specifications

Upon completion of the design verification process, the manufacturer should have the technical specifications available for the HPHT equipment provided. The manufacturer’s technical specifications should demonstrate conformance to the equipment’s functional requirements of Section 5.1 in this technical report. Additional guidance on developing a technical specification can be found in ISO 13880. API PER 15K-1 provides additional guidance on elements of the manufacturer’s technical specifications and API 17Q provides documentation guidance.
6. Materials for High-Pressure High-Temperature Equipment

6.1 Selection of Materials

The material selections for HPHT applications should consider the following service conditions, as these will affect the material properties:

1) Environmental conditions
2) Exposure to fluids, liquids and/or gases which contact the equipment surfaces, i.e., \( \text{H}_2\text{S}, \text{CO}_2, \) Chloride, seawater, etc.
3) The effects of temperature (elevated) on material properties
4) Cathodic protection (CP)

Additional guidance on material selection for HPHT components with consideration to the service conditions outlined above is provided in Annex B of this technical report. Guidance for material QC processes is provided in Annex C of this technical report.

6.2 Environmental Effects

6.2.1 General

Environmental conditions can have significant effects on material properties. Environmental effects on materials should be evaluated for input into the design verification analyses. Both thermal and fluids degradation should be considered for each material specification within an HPHT component.

6.2.2 Sweet Corrosion - \( \text{CO}_2 \)

\( \text{CO}_2 \) in the presence of water forms carbonic acid, which is corrosive. The most common form of sweet corrosion may result in uniform weight loss in carbon and low alloy steels (LAS), which can be predicted using available models. Factors affecting the corrosion rate include partial pressure of \( \text{CO}_2 \), temperature, water content, flow rate, and pH of water phase. Depending on temperature and pH, a protective scale layer may form on carbon and LAS, which reduces the corrosion rate. However, if local breakdown of the protective scale occurs by turbulent flow, localized corrosion may occur.

The presence of oxygen or organic acids may also reduce the protectiveness of the scale. The localized corrosion in carbon and LAS also occurs in gas fields where the temperature along the pipeline falls below the dew point and gas condensate containing \( \text{CO}_2 \) begins to form along the tube walls. "Top of the line" corrosion in gas field pipelines is an example of this corrosion mechanism. Sweet corrosion can be mitigated by the use of a qualified corrosion inhibitor for carbon and LAS or proper material selection.

6.2.3 Sour Corrosion - \( \text{H}_2\text{S} \)

\( \text{H}_2\text{S} \) corrosion in the presence of tensile stress may result in a form of hydrogen embrittlement known as sulfide stress cracking (SSC). SSC is typically catastrophic. It is often delayed, but happens abruptly with no visible warning and may happen at stresses well below the yield strength. Factors contributing to SSC include partial pressure of \( \text{H}_2\text{S} \), temperature, pH, and presence of \( \text{CO}_2 \), chlorides, other halides, and stress.

In sour environments, SSC can only be avoided through proper selection of materials. Corrosion-resistant alloy (CRA) cladding of carbon and LAS with ERNiFeCr-1 or ERNiCrMo-3 (depending on the severity of the environment) can be used as a mitigation barrier with regards to SCC. ANSI/NACE MR0175/ISO 15156 serves as the industry guideline for selection of materials for sour service. ANSI/NACE MR0175/ISO 15156 defines sour service as having a partial pressure of \( \text{H}_2\text{S} \) equal to or greater than 0.05 psia. All high-pressure wells should be treated as sour and given consideration to the possibility that the \( \text{H}_2\text{S} \) content may increase over the life of the well. There is a strong correlation between the hardness, composition, microstructure, and processing of materials and their SSC susceptibility.
6.2.4 Chloride Corrosion

Chlorides result in general and localized corrosion of carbon and alloy steels by lowering the pH of the environment. This may be addressed with coatings or the use of corrosion resistant alloys. Some CRAs are prone to localized corrosion in the form of pitting or crevice corrosion and stress corrosion cracking (SCC) in chloride containing environments. Alloys with a high pitting resistance equivalent number [(PREN), Refer to Annex B.1.2] should therefore be used. A minimum PREN of 40 is needed to prevent localized corrosion in seawater.

CRAs may also be selected based upon their critical pitting temperature (CPT) and critical crevice temperature (CCT) below which pitting and crevice corrosion does not occur. Chlorides in the presence of tensile stresses may also lead to SCC at elevated temperatures. Alloys with higher nickel content are more resistant to SCC.

6.2.5 Hydrogen Embrittlement in Sea Water with Cathodic Protection

Cathodic protection of metallic materials submerged in seawater may result in formation of hydrogen protons through direct reduction of the seawater. Hydrogen protons may diffuse into metal and cause hydrogen embrittlement of susceptible microstructures. Detection of hydrogen embrittlement in subsea equipment is unlikely. Depending upon the specific conditions, such as extent of the cracking, toughness of the material, etc., hydrogen embrittlement may lead to rapid fracture at stresses below the yield strength.

Methods for preventing hydrogen embrittlement include barrier coatings and material selection with hardness below a threshold value. An industry standard does not exist for ranking the susceptibility of alloys to hydrogen embrittlement. Lower strength alloys and those with low inclusion and precipitate content are less prone to hydrogen embrittlement. Nickel-based alloys are generally superior to steels in resistance to hydrogen embrittlement.

6.3 Material Properties for Design Verification

Table 6.1 identifies industry standards applicable for the determination of material properties to be employed as input to the design verification/analysis (linear-elastic or elastic-plastic analysis) and fatigue assessment (S/N or FM approach), as defined in Section 5 of this technical report. All test specimens shall be in final heat-treated condition, including temper and post weld heat treatment (PWHT), as applicable.

In this regard, for linear-elastic FEA, the following material properties are typically required as input into the analysis material model:

1) Yield strength
2) Modulus of elasticity (Young’s Modulus)
3) Poisson’s ratio

For elastic-plastic FEA, the following material properties are typically required as input into the analysis material model:

1) Yield strength
2) Tensile strength
3) Modulus of elasticity (Young’s Modulus)
4) Poisson’s ratio
5) Thermal properties, as applicable
6) True-stress true-strain data (with work hardening). For elastic-plastic analysis, it is recommended that the true-stress true strain material model to be used and that the material be represented as perfectly-plastic beyond the ultimate tensile strength or the actual material test data is used. A true-stress true-strain curve can be obtained from ASME Div. 2, Annex 3D or ASME Div.3 Article KD 231.4. If a stress-strain curve from actual testing is used, appropriate corrections may be needed to ensure that the data used in the analysis is representative of the minimum specified yield strength of the material. The effect of the specified maximum design temperature on material properties shall be considered.
Table 6.1: Industry Standards for Determination of Material Properties Required for Design Verification

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Equipment Design Requirements</th>
<th>Reference / Source</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pressure Containing</td>
<td>Pressure Controlling</td>
</tr>
<tr>
<td>Tensile Properties (Yield, Tensile, Elongation and Reduction of Area)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Room Temperature, 75°F</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Elevated Temperature (100°F increments to 100°F above the specified design temperature)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Modulus of Elasticity (Young’s Modulus)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Modulus of Elasticity @ 75°F</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Modulus of Elasticity (100°F increments to 650°F)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Toughness</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CTOD</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>KIC/KIC</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Fatigue Properties</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Crack Growth Rate, da/dN</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Fatigue Test (S/N)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Nondestructive Examination</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NDE</td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>

Guidance Notes for Table 6.1:

1) Material property development (specimen size, orientation, location, etc.) in air is defined by ASTM standards. Mechanical property evaluation (tensile) should be conducted at the intended project temperature or above.

2) Additional properties required for design including FT (in seawater + cathodic protection and produced fluids) should be taken from a minimum of two (2) heats with a minimum of three (3) samples for each heat.

3) For S/N fatigue (strip specimens) in sea water + cathodic protection and produced fluids, a minimum of two (2) heats should be evaluated with three (3) samples each at low cycle range, three (3) samples at mid cycle range and three (3) samples at high cycle range (eighteen samples total). The acceptable design curve would be means + 2 standard deviations (SD).

4) For fatigue crack growth rate (in seawater + cathodic protection and produced fluids) samples should be taken from a minimum of two (2) heats with a minimum of three (3) samples for each heat (six (6) total specimens). The test variables such as frequency (Hz) and stress ratio (R) can be considered project specific and may require additional data development for these parameters.

5) The test material should be of equivalent grade and processing as that of the production component.
As an alternate to the true-stress true-strain properties defined in ASME Div. 3, Article KD-231.4, the material can be tested according to ASTM E8, ASTM E21 and ISO 6892. The test should provide tabulated load displacement values converted to engineering stress/strain and true stress strain up to ultimate strength of the test specimen. Rate of straining or rate of stressing should be defined for each test. Elongation, reduction in area, elastic modulus and strain hardening coefficient should be defined for each test. Increments for test temperature should have a maximum of 100°F for all tests above 250°F. Other material models, such as tangent modulus, bilinear stress-strain curve, may also be useful in some cases.

6.4  Material Properties for Fatigue Assessment

6.4.1  General

Fatigue can be a significant design consideration for offshore and subsea applications. Fatigue loading arises due to vessel motions that are caused by wave and current action, as well as pressure and/or temperature changes during the well production phase. Fatigue evaluation of materials for use in oil and gas applications is either based on stress-cycle (S/N approach) or fracture mechanics (FM approach) by means of FCGR and FT.

6.4.2  S/N Fatigue Curve

The basis of S/N fatigue curve is to determine a plot of alternating constant-amplitude applied stress range (Δσ), versus cycles to failure, Nf. A typical S/N curve plot shows an increasing cycles to failure as the applied alternating stress range is reduced. S/N fatigue data in production environment and seawater plus cathodic protection should be developed at similar test cyclic frequencies as would be used to develop fatigue crack growth rates. A test cyclic frequency of 0.2 - 0.3 Hz is recommended in both environments. Limited existing data show that tests that survive 10,000,000 cycles without failure are defined as “run-outs”.

Environmental preparation for determination of S/N fatigue data in production environments should follow standard ANSI/NACE MR0175/ISO 15156 procedures. Development of S/N data in seawater plus cathodic protection should be performed in simulated seawater prepared in accordance with ASTM E1141.

For structural loading conditions, the equipment designer may select to use the S/N curves provided in DNV-RP-C203.

6.4.3  Fatigue Crack Growth Rate

6.4.3.1  General

The FM approach considers the FCGR determination of a component or pipe material that contains an initial crack length that can be described by linear-elastic fracture mechanics (LEFM) of ASME Div. 3. To develop the fatigue crack growth rate, specimen orientation should be in accordance with ASTM E399. The fatigue crack growth specimens extracted from pipe material should be oriented in the L-C orientation as designated by ASTM 399. The L-C orientation indicates that the specimen is oriented so that primary loading occurs in the pipe longitudinal direction while crack propagation occurs in the circumferential direction. Fatigue crack growth rate determination procedure should be in accordance with ASTM E647.

Materials used for deepwater oil and gas applications are either exposed to production environments (may contain H2S) or seawater plus cathodic protection. Limited existing data for certain group of materials such as low-alloy steels (LAS) show increase in fatigue crack growth rates in seawater plus cathodic protection and production environments (may contain H2S), respectively as compared to the base line data in air.

Materials which are susceptible to the exposed environment should be tested for environmentally assisted cyclic fatigue crack growth, da/dN vs. ΔK. Tests should be conducted in accordance to ASTM E647. Both temperature and fluid chemistry should be considered in these tests.

6.4.3.2  Fatigue Crack Growth: Production Fluids

Limited existing data for LAS show that FGCR for most materials in production environments is highly dependent on cyclic load test frequency. That is, the lower the cyclic frequency, the higher the fatigue crack growth rate. As a result, frequency-scan experiments should be conducted to assess fatigue crack growth rates over a range of cyclic loading frequencies under a constant crack “driving force”. The goal of the test is to determine a saturation frequency below which the crack growth per cycle no longer increases with decreasing frequency. Actual testing should be performed at the saturation frequency determined from frequency scan experiments. Environmental preparation for determination of FCGR in production environments should follow standard ANSI/NACE MR0175/ISO 15156 procedures.
6.4.3.3 Fatigue Crack Growth: Seawater and Cathodic Protection

The outside surface of equipment used in subsea applications is normally protected from seawater corrosion by CP with sacrificial anodes. The surface potential achieved by sacrificial anodes is typically between -950mV to -1100mV (vs. Ag/AgCl). At these potentials, direct reduction of water occurs on the exposed surface producing enough atomic hydrogen to diffuse into susceptible materials, reducing its FT and fatigue performance. Limited existing data for materials such as LAS show that exposure of these materials to seawater and CP increases its FCGR as compared to baseline air data.

Development of FCGR in seawater plus cathodic protection should be performed in simulated seawater prepared in accordance with ASTM E1141. Simulated seawater has adequate electrical conductivity but lower ionic species that contribute to formation of calcareous scale on the surface of the test specimen that can affect the results.

FCGR in seawater and cathodic protection similar to production environment is also affected by cyclic frequency and shows an increased growth rate at low frequencies.

6.4.4 Fracture Toughness Evaluation

6.4.4.1 General

FT is a critical parameter for a fracture mechanics evaluation of planar (crack-like) flaws in components. The presence of hydrogen in a material can lead to a significant reduction in the apparent fracture toughness due to its embrittling effects. Atomic hydrogen can be generated from the production environment or through CP.

6.4.4.2 Fracture Toughness: Sour Production Environments

FT values in sour environment to be input into the FM evaluation should be determined using either linear-elastic or elastic-plastic fracture mechanics based on the applicable material properties. While constant displacement tests (DCB) adequately describe the FT behavior of relatively less ductile materials, rising displacement test (J-R curve method) is required to ascertain the FT of materials that exhibit elastic-plastic behavior. Depending on the yield strength of the material, DCB tests have a limited range of stress intensity factors (K) over which they are valid. Therefore, current industry practice for FT assessment of materials exposed directly to sour environments is to utilize a toughness parameter known as \( J_{1C} \), which can be converted to equivalent parameters in terms of \( K_{1C} \).

The J parameter for a material of interest in a corresponding environment should be determined by generating a J-R curve, also known as fracture resistance (R) curve, as described below:

1) FT testing should be performed in accordance with ASTM E1820 standard.

2) All FT tests should be performed in a representative sour production environment at relevant temperatures to simulate both production (high temperature) and shut-in conditions (low temperature).

3) Test specimen geometry should comply with ASTM E399 and ASTM E1820; however, single-edge-notched bend (SENB) type specimens are generally utilized for generating J-R curves.

4) The recommended loading rate (K) for FT testing of carbon steels and LAS is 0.0014 ksi√in/s (0.05 Nmm\(^{3/2}\)/s), under rising displacement control. Other recommended loading rates may be acceptable depending upon the material selected and previous experience/ repeatability. This low K-rate will enable sufficient time for diffusion of hydrogen through the fracture process zone to cause damage and lower the toughness, thereby providing conservative values.

5) Testing should be performed using a single specimen method. The crack-mouth opening on the CTOD specimen during the test should be measured using a clip gage in-situ.

6) The J-R curve and CTOD-R curve from testing should be reported along with J and CTOD at maximum load.

These requirements are in addition to the material testing necessary requirements that are part of the qualification process for cracking resistant carbon/LAS and CRAs (e.g., ANSI/NACE MR0175/ISO 15156).
6.4.4.3 Fracture Toughness: Seawater with Cathodic Protection

Fracture resistance of materials that are exposed to seawater and subjected to CP in service should be evaluated through determination of their FT characteristics in simulated seawater prepared in accordance with ASTM D1141-98. Cathodic charging should be simulated through application of appropriate CP potential values to the test specimen, as determined through measurements of surface potential achieved by sacrificial anodes utilized in service. It is generally recommended to perform cathodic charging at potential values ranging between -950mV to -1100mV (vs. Ag/AgCl) as further explained in Section 6.4.2.2.

FT evaluation using a J-R curve approach should be conducted in the simulated seawater environment (with CP) by following the guidance provided in Section 6.4.3.1.

6.5 Integral Cladding / Weld Metal Overlay

6.5.1 General

Base materials over which integral cladding or weld metal overlay materials are applied should satisfy the design verifications of Section 5 of this technical report. The integral cladding or weld metal overlay materials must be considered as part of the pressure-containing component structure. Both integrally clad and weld metals used for internal corrosion-erosion resistance should be evaluated for physical and mechanical properties defined in Section 6.3 and the NDE requirements of Section 6.6, as applicable. Integral cladding and weld metal overlays should meet the requirements of API 6A and Section 6.5.2 of this technical report.

6.5.2 Qualification of Procedures

Each welding process or integral cladding process should be qualified in the form and arrangement to be used in construction and with materials that are within the ranges of chemical composition of the base metal, the integral cladding and the weld metal. An overlay thickness for qualification testing should be defined based on the design verification/analysis requirements defined in Section 5 of this technical report.

Fabrication welding and welders/welding operations should be qualified in accordance with applicable internationally recognized standards such as ASME Section IX, ANSI/NACE MR0175/ISO 15156, or equivalents.

6.5.3 Mechanical Properties Testing and Fatigue Testing

Integral cladding or weld metal overlay materials should be tested for mechanical properties as defined in Section 6.3 for input into the design analyses. The properties for the base metal, integral cladding and/or weld metal must be tested after completion of PWHT. Integral cladding or weld metal overlays which are used in designs where the tension loading is applied to the bond line should be tested for mechanical properties in the transverse direction across the bond line.

Guidance is provided in Section 6.4 of this technical report for fatigue testing of integral clad layer or weld metal overlay, as applicable.

6.5.4 NDE Procedures and Acceptance Criteria

The welding procedure qualification testing and production integral clad or weld metal overlay should be inspected for volumetric and surface indications with the corresponding acceptance criteria defined in Annex C of this technical report. The production base material should be volumetric and surface NDE inspected prior to and after cladding or overlay procedures are completed.

6.6 Nondestructive Examination

6.6.1 General

NDE and the acceptance criteria are to be performed in accordance with the governing design standard and/or the equipment PSL’s designation. Multiple methods of NDE may be employed to detect flaws in components. Some NDE methods are only suitable for examining the surface of components while other NDE methods are suitable for volumetric examination. Additional guidance on NDE methodology and appropriate application are provided in Annex C of this technical report.
NDE personnel considered for the performance of these examinations should have the necessary experience, training, certifications, and qualifications per ASNT SNT TC 1A, ASNT CP-189 or equivalent.

An indication classified as a flaw because it is larger than the acceptance standard may be deemed acceptable provided additional analysis of the flaw, such as location, orientation, nature, and size, to determine the component’s “fitness for service” for the duration of the intended service life. Acceptance of flaws larger than those permitted by the acceptance standard should be approved by the responsible person within the organization.

6.6.2 NDE for Fracture Mechanics - ASME Div. 3

NDE procedure shall be determined by the required sensitivity to achieve the necessary PoD in sizing capability, as determined by the smallest allowable defect deriving from the agreed acceptance criteria and as agreed upon between the manufacturer and the material producer. In addition to individual indications, design should also consider the possibility of multiple, closely spaced indications that may interact and behave as an individual planar flaw.

The maximum allowable flaw size, location, and orientation of individual flaws as well as the size, spacing, and number of closely spaced flaws (multiple flaws), will be defined based on the design verification process. The selected NDE method must demonstrate its capability to detect the defined flaw size reliably.

6.6.3 NDE Reliability Demonstration for Fracture Mechanics - ASME Div. 3

The objective of an NDE reliability demonstration is to determine the PoD versus an actual flaw size relationship. This process defines the performance of an NDE method and procedure under certain manufacturing conditions. Variation in NDE methods and procedures produce various responses and subsequently cause an uncertainty in the detect-ability of a flaw. This is a combined product of both the physical attributes of a flaw and the NDE process parameters.

The uncertainty caused by differences between flaws is accounted for by using representative test specimens with flaws of a known size to demonstrate the effectiveness of the NDE test method. The uncertainty caused by the NDE process can be accounted for by a qualification test of different examinations on various test specimens. If the test is properly conducted, a secondary objective of identifying those factors which influence the PoD for the system may be achieved (i.e., part geometry, part finished surface condition, part temperature, process and system parameters, etc.).

6.6.4 Probability of Detection

The PoD for a given indication depends upon a variety of conditions, which may include but not be limited to:

1) The specific NDE method employed
2) The training and skill of the technician
3) The condition of the surface of the component being examined
4) The environment (i.e., lighting, orientation of component, etc.) under which the examination is performed
5) The nature (planar or volumetric) of the indication
6) The location, orientation, and size of the indication

More specifically, the PoD of a large indication is typically higher than the PoD of a relatively small indication. All conditions that influence the PoD of indications should be considered when establishing acceptance standards for QC examinations. The application of ASME Div. 3 for fracture and fatigue analyses in the design of a HPHT component requires a comprehensive understanding of the PoD of relevant flaws in that component.
7. **Seals and Fasteners**

7.1 **General**

The selection of seals, metallic or non-metallic, should consider a thorough system evaluation addressing all seals needs to be conducted and their interaction with the sealing body.

7.1.1 **System Level**

The seal evaluation and selection should be derived from the parameters as specified in the HPHT equipment function specifications, which should include, but not be limited to:

1) Operating pressure / Equipment pressure rating
2) Anticipated operating temperature (minimum / maximum)
3) Cyclic expectations (pressure and temperature)
4) Defined operational models that identify:
   a) Periods or duration at operational limits (pressure and temperature)
   b) Planned schedule of events, i.e., time on production, shut-in, workover, maintenance, etc.
   c) Potential emergency events, i.e., retrieval, unplanned maintenance, abandonment, etc.

The selection of seals should be identified by its pressure and temperature rating. In addition to the above, the following considerations should be identified for seals in high-temperature (HT) applications:

1) **Dynamic Characteristics:** In addition to the operational (static) requirements, the following “dynamic” characteristics that are associated with seal for HPHT application and they are:
   a) Installation
   b) Removal
   c) Long duration static followed by dynamic
   d) Pure dynamic (speed)

   Dynamic requirements should be identified with the anticipated time under these various dynamic considerations. Additionally, "movements" or deflections/displacement should be anticipated for seals under the dynamic conditions.

2) **Validation Testing of Seals:** Validation testing must reflect system dynamic behavior as well as seal dynamic behavior. Validation testing should be a realistic representation of key characteristics, e.g., potential galling of materials, tribology, vibration, cavitation (rapid release of energy can cause material loss leading to problems). Flow assurance analysis through computational fluid dynamic (CFD) analysis should be conducted to identify any cavitation around seals.

3) **Rapid Gas Decompression (RGD) Potential:** Clear definitions of any potential RGD events should be defined for all seal within a selected sub-system or systems, as applicable. Seal "system" design may be used to compensate for limited material qualification for RGD resistance. When possible, RGD validation should be performed on representative seal geometry. Seals or seals systems having elastomeric components should be subject to RGD evaluation.

4) **Thermal Gradients:** System thermal analysis can be used to identify the operating temperature limits (maximum and minimum) for all seals throughout a system evaluation. Based on the results of the thermal analysis, selection of seals should be based on the maximum resultant temperature. Additionally, validation of seals can potentially be conducted at a lower temperature than the design temperature, based on the results of the system thermal analysis. Guidance on the validation of the system thermal is provided in Section 8 of this technical report.
5) Fluid Compatibility: All fluids used over the life of the well needs to be identified and understood in their effects on selected seal materials. Expectations for each seal in a system to fluid exposure (type/duration) should be evaluated for the following conditions:

a) Wellbore / Production fluids: Considerations to the following scenario should be identified and documented:
   1) Accurate fluid composition data should be made available or sealing system should be designed for worst case conditions
   2) Justification of sealing material selection with respect to fluid compatibility should be programmed taking into account design function/enhancement/compensation
   3) Potential for long term changes in fluid composition
   4) Water cut
   5) Souring effects
   6) Acidic levels - pH

b) Injected fluids: An injection plan should be confirmed and agreed between all parties concerned. Any deviation from the plan should require notification to all parties, and a compatibility assessment to the injected fluids should be performed. Potential of corrosion to sealing surfaces from the injected fluids should be assessed.

c) Control fluids: Throughout consideration to the cleanliness requirements of control fluids needs to be addressed when selecting or designing seals, where contamination from seal material must be eliminated. Compatibility of seal materials with control fluids needs to be assessed and documented in system analysis.

7.1.2 Life-Cycle

Life-cycles for seals should consider their shelf-life, operating life and maintenance plan. A shelf-life for all non-metallic seals should be established and documented. Storage conditions for all seals should be established and documented in accordance with the manufacturer's requirements. Operating life requirements for seals should be defined and agreed between all parties concerned. Methods to determine life expectancy utilizing short duration validation tests should be established and agreed between all parties. A maintenance program to address seal replacement or refurbishment should be established and include all necessary verification and re-validation requirements to establish adequacy for intended service.

7.1.3 Critical vs. Non-Critical Applications

Ramification of potential seal failure should be considered to determine the impact/consequences of leakage and to make a decision whether failure is an inconvenience requiring eventual remediation or a catastrophic event requiring immediate intervention. Seals should be classed based on the preceding criteria and assigned a classification which will drive verification and validation requirements.

7.1.4 Barrier Philosophy

Seals to the environment should be of the highest criticality class and redundancy should be considered with each selection of the primary seal. Validation to ascertain high reliability should be considered for primary seals to the environment. This may require multiple tests or testing to failure with high cycle acceptance criteria. Refer to Section 8, Design Validation.

7.1.5 Seal Areas

There are a number of dynamic (e.g., some movement is possible) and static seal areas in pressure-containing components. It is necessary to ensure that there is little or no damage to the metal-to-metal seal faces in these regions. For example, even relatively superficial pitting that would not otherwise be considered to compromise the integrity of the equipment is unacceptable on the seal faces as it can prevent sealing and/or ‘tear’ elastomer seal during movement. Therefore, it may be necessary to select more corrosion-resistant materials options for these areas of the components or weld overlay with more corrosion resistant materials, especially in the case of dynamic seals.
7.2 Material Selections

7.2.1 General

Seals must be designed using material properties at the extreme limits of the environment for the defined life of the product. High temperatures can accelerate corrosion processes while at the same time reducing material properties. Seal design subject to tensile load must be assessed for SCC and HIC. In determining the stress mode, consideration must be given to combined stresses of thermal gradients, applied pressures, bending of system components to ensure that an accurate determination has been made of the net stress of the component.

7.2.2 Metallic Seal Materials

Metallic seals should have adequate material properties to comply with their intended service. Design verification of HPHT equipment should account for metallic seals and their interaction with mating parts. It should be recognized that the elastic limit of the materials may be deliberately exceeded; however, the seals should maintain their operational requirements. Additional considerations to metallic seals for HPHT applications are as follows:

1) Corrosion: Corrosion can be accelerated by temperature, and it is dependent upon chemical reactions. Therefore, materials must be inspected in the HT environment with the fluid and material combinations of actual service to consider the following:
   a) Galvanic: When assessing the seal system for galvanic corrosion consideration must be given for the increase in rates due to the higher temperature but standard engineering practices for galvanic couples may be followed.
   b) SCC: Use good engineering judgement to evaluate the impact of HPHT to SCC rates.
   c) SSC: Traditionally, defined standard service environments due to low percentage concentration of H₂S, may actually be sour service due to a high partial pressure H₂S due to because of the overall high pressure of the system.

2) Differential Thermal Expansion: Current designs that are used for lower normal temperature ranges must be justified using engineering judgement to take into account differential thermal expansion due to HPHT. HPHT environment creates greater deflections so current designs must be re-evaluated for the greater ranges. Analysis needs to be conducted over the entire temperature range to ensure that seal loading is maintained over the entire range.

3) Galling: Galling may result from a small relative movement due to alternating bending, thermal expansion/contraction caused by temperature cycles, ballooning/contraction and Poisson’s affect because of pressure cycles. Considerations should be taken in the material selection to minimize galling potential.

4) Fretting: At higher temperatures, corrosion rates increase. Fretting corrosion can be a greater concern for materials that have a passivation layer that is consistently being damaged.

7.2.3 Non-Metallic Seal Materials

Non-metallic seals should be provided with PSL4 in accordance with API 6A. Non-metallic seal materials should consider the following:

1) Aging: Material aging due to temperature and fluid exposure should be identified in the material selections of non-metallic seals. Life estimation testing that meets or exceeds the general requirements of API TR 6J1 should be conducted.

2) Differential thermal expansion: Thermal expansion due to the high temperatures, component size changes, movement, extrusion gaps, etc., will be of greater magnitude for HT services, and therefore, must be considered more carefully and accounted for in the test fixture design or validation testing in order to represent the actual production equipment and operating environment.

3) Stress relaxation: Designs where the seal does not have an additional energizing mechanism need to be validated for stress relaxation and/or compression set (examples of additional energizing mechanism include internal spring activated, pressure activated).
4) Thermal effects on lubricants and seal materials: Verify lubricant compatibility with environment and seal materials, e.g., use of special high temperature lubricants for assembly purposes to be validated and used without substitutions that have not been similarly tested.

7.3 Design Considerations

Full analysis performed to determine the component geometry at the extremes of the temperature and pressure range to ensure that key design parameters meet manufacturer’s requirements and representative validation testing is acceptable when those key design parameters remain constant across different sizes. Design verification should take into consideration the following:

1) Creep due to high pressure/temperature
2) Representative validation
3) Metallic seals
4) Application damage consideration
5) Failure mechanisms
6) Coatings
7) Non-metallic seals
8) Consistency of critical properties (batch tolerance)
9) Design life determination
10) Volume fill
11) Multiple component seal system considerations

8. Design Validation

8.1 General

The design validation process is required to demonstrate that the equipment maintains the mechanical integrity and functionality to its functional specifications. Design validation is defined in API Q1, and it should have the following components:

1) Validation (testing/qualification) of a component and/or system under development.
2) Validation of the design method: Model predictions (i.e., FEA, thermal analysis, fatigue analysis, fracture mechanics, etc.) should be validated. Historical verification processes can remain valid if they can be documented, demonstrated as technically sound, and meet the equipment design requirements and service conditions.
3) Validation of materials used for the design: Material properties, service and application limits used in the analyses should be based on test data or recognized sources/literature. Degradation mechanisms that should be considered in the material validation process may include, but not be limited to, temperature, corrosion, fatigue, SCC, HIC, and erosion/corrosion, etc.

API PER 15K-1 provides additional guidance for the design validation process, and API 17Q provides guidance on the documentation requirements for the validation process.
8.2 Minimum Design Validation Requirements

The governing design standard (e.g. API 17D) defines the minimum validation requirements. Additional validation requirements should be identified by the FMECA generated in the design verification process and in this technical report. Equipment is to be validated for the intended service application and service life to demonstrate that the design and functional requirements have been met.

8.3 Additional Design Validation Requirements

As described in Section 5, FMECA is conducted to identify the failure modes of the equipment under the specified service conditions. The FMECA process provides the basis for the development of a design validation testing program.

The end user and manufacturer should jointly develop the design validation program, subject to the minimum requirements as described above. Requirements in excess of those defined as minimum requirements should be categorized as follows:

1) PR3: The additional requirements associated with validating the design in terms of the required lifecycle of the equipment from a performance and functionality perspective (e.g. wear, erosion, corrosion, material degradation) plus the minimum requirements described above.

2) PR4: The additional requirements associated with validating the design in terms of the required lifecycle of the equipment from a structural integrity perspective associated with fatigue, plus the requirements of PR3.

The HPHT Design Flow Chart illustrates the linkage between the design verification process and the design validation requirements through the fatigue sensitivity screening or fatigue assessment for HPHT equipment.

For equipment that, based on the fatigue screening process, is not susceptible to fatigue failure in the specified service conditions, validation requirements may be restricted to those categorized as PR3 or PR2.

For equipment that, based on the fatigue screening process may be susceptible to fatigue failure in the specified service conditions, validation requirements are as described as PR4.

The use of the PR3 and PR4 designations provides a general indication of the extent of validation testing requirements, but specific requirements should be defined between the end user and the manufacturer, and the FMECA analysis.

8.4 Revalidation of Existing Designs

A material change may require design re-verification but may not require additional design validation testing. Changes or modifications to the components should be assessed to determine its effect to the component and to reassess the validation program, as necessary. Additional guidance on effects on changes in product as related to re-validation is provided in Annex F, F.1.2 of API 6A.

8.5 Use of Equipment Subjected to Validation Testing

Components used in the validation process may be subsequently placed into service if it can be demonstrated that they can meet the required design and service life.

8.6 Validation Testing Considerations

8.6.1 Validation Program

A validation program may include, but not limited to, the following:

1) Material characterizations (metallic and non-metallic)

2) Erosion / Corrosion testing

3) Multiple samples
4) Instrumentation (strain gauging, accelerometer, etc.)
5) Fatigue testing (defined limit or to failure)
6) Hyperbaric testing
7) Flow testing
8) Thermal performance testing (i.e., cool down, thermal gradient, etc.)
9) Load testing to a defined performance envelope (i.e., tension, compression, bending, pressure, temperature, etc.)
10) Load testing to failure (individual or combined loadings)
11) System integration
12) Independent / Third-party testing
13) Post-test results analysis
14) Post-test NDE
15) Post-test dimensional inspection
16) Post-test fatigue damage assessment

8.6.2 Test Specimens
Specimens used for validation testing should be representative of the equipment to be placed into service in accordance with the component’s design or testing standards.

8.6.3 Test Programs
Test programs should be designed to achieve the required confidence in the results. Additional guidance on confidence in validation can be found in API 17N.

8.6.4 Number of Samples
The number of samples to be tested should take into consideration the repeatability of the test results and validate analysis results. Additional guidance on number of samples for the design validation testing can be found in API 17G.

8.6.5 Evaluation of Results
The data gathered from testing should be evaluated to ensure that anomalies are understood and, where applicable eliminated from consideration if the reason for the anomalous result is determined.

8.6.6 Scale Model Testing
Scale model testing is a useful tool to validate a design concept. Scale model testing may aid in the design of the final product validation test design. Scale model testing may be used for fatigue testing.

Note: This does not imply the acceptance or rejection of API 6A scaling criteria.

8.6.7 Full-Scale Prototype Testing: Assemblies or Components
Where the interaction between components can be defined by validated analytical methods, i.e., scale model testing etc., the validation testing of individual components or sub-assemblies may be deemed to validate the assembly.
8.7 In-Service Validation

Design validation may continue once the equipment is placed into service. Examples of in-service validation methods are:

1) Load monitoring and recording (Refer to Annex A)
2) Remaining life assessment
3) Condition/performance monitoring (operating signature)
4) Leak detection
5) Cathodic protection system monitoring (anode condition)

8.8 Validation of Nondestructive Examination

Confirmation of the selected NDE examination method utilized to determine the initial flaw size for analyses must be demonstrated by the manufacturer for adequate levels of detection and resolution. NDE should be conducted in accordance with the examination methods of ASME Section V. Personnel performing NDE should be qualified and certified in accordance with ASNT SNT-TC-1A. Additional guidance on validation of NDE is provided in Section 6.6 of this technical report.

8.9 Validation of Analytical Methods

Where testing, i.e. strain gauging, is used to validate an analytical method, the placement of measuring devices should be carefully correlated with the locations of peak loading and stress to ensure that potentially problematic areas are properly considered. Valid calibration of measuring devices is required to be current with manufacturer’s quality management system. Calibrations should be traceable to a recognized national standard (i.e., NIST, ANSI, etc.).

9. Hydrostatic Test for High-Pressure High-Temperature Equipment

9.1 General

Each pressure containing component manufactured should be subjected to a hydrostatic test pressure which, at every point in the component, is within the range of specified test pressure. Water or water with additives is to be used as the testing fluid. Tests are to be completed prior to painting and prior to the addition of body-filler grease. Lubrication applied during assembly is acceptable. Hydrostatic testing is conducted to verify the component will not leak under any combination of operating conditions.

The hydrostatic test pressure shall not exceed the specified pressure more than 2%. All hydrostatic testing shall be conducted at room temperature conditions. Hydrostatic test procedures, sequencing and hold times should meet the requirements of API 6A. The hydrostatic test pressures are defined as follows in Section 9.1 and Section 9.2.

9.2 Pressure Rating ≤ 20ksi

In general, hydrostatic test pressure shall be a minimum of 1.5 times the equipment rated working pressure (RWP) to be marked on the vessel. However, if the design verification is performed using ASME Div. 3 design practices (Refer to Figure 5.1) then a minimum test pressure of 1.25 times the RWP shall be considered acceptable.

9.3 Pressure Rating > 20ksi

For pressure rating > 20ksi, the hydrostatic test pressure shall be a minimum of 1.25 times the equipment RWP to be marked on the component. The maximum allowable temperature rating for this hydrostatic test pressure is 550°F (288°C).

The specified hydrostatic test pressure limit of 1.25 times the RWP has been defined based on the following technical requirements and/or justifications for HPHT equipment:
1) API materials are limited in yield strength when required to meet ANSI/NACE MR0175/ISO 15156.

2) The limits on yield strength are such that the triaxial stresses and strains must be controlled under maximum loading conditions particularly for equipment with > 20ksi RWP, when tested at hydrostatic conditions.

3) API pressure-containing components constructed of LAS conforming to the requirements of ANSI/NACE MR0175/ISO 15156, having limits on yield strength, typically show an exponential increase in plastic strains and triaxial strains as a function of pressure at > 20ksi RWP.

4) It is documented that material voids [1], which may be smaller than the acceptable limits of the NDE inspection, can lead to an amplification of relative void growth rates over imposed strain rates by an exponential factor of the mean normal stress when exposed under moderate to high triaxiality stresses.


5) Limits on the maximum hydrostatic test pressure must be defined to minimize void or flaw growth to avoid a reduction in service performance of the component, particularly for cyclic loading.

6) Limits on the maximum hydrostatic test pressure must be defined to assure material strain hardening due to plastic deformation will not increase its sensitivity to environmental degradation.
Annex A
Load Monitoring
(Informative)

Where necessary, load monitoring scheme of the product may be considered in order to confirm the design parameters utilized in the design verification process against the actual operating conditions. Monitoring the condition of subsea equipment, other than by remotely operated vehicle (ROV) inspection is challenging, but monitoring of loads, load cycles, deflections, etc. can be used to validate the design. Consideration should be taken to incorporate such monitoring equipment into the design, where warranted.

Load history monitoring can be used to estimate the proportion of remaining life when compared to analytical results and test results. For a load monitoring program, the reliability data for instrumentations, sensors, and signal transfer should be satisfactorily demonstrated. Data storage for analysis should be provided with the load monitoring program. The validation program should include the assessment and validation of the subsea load monitoring reliability to verify that the predicted reliability can be achieved.
Annex B
Material Selection
(Normative)

B.1 General

This annex describes the material selection for application requirements such as pressure containing (parts whose failure to function as intended results in a release of well bore fluid to the environment), pressure controlling (parts intended to control or regulate the movement of pressurized fluid), load bearing or combined pressure containing-load bearing, fasteners, and seals.

B.2 Pressure Containing

B.2.1 General

The evaluation and design of pressure containing equipment should consider exposure of fluids, liquids and gases, which contact the equipment surfaces. As an example, these fluids may be produced fluids or well stimulation fluids (which could be considered sweet or sour), completion brines, seawater, or seawater plus cathodic protection.

B.2.2 Sour Service Application

ANSI/NACE MR0175/ISO 15156 “Materials for Use in H₂S-Containing Environments in Oil and Gas Production” defines the oilfield environment as ‘sour’ if the partial pressure of H₂S gas is equal or greater than 0.05psia (0.3kPa) and ‘sweet’ refers to conditions where the partial pressure of H₂S is less than that for ‘sour’ conditions [i.e. < 0.05psia (0.3kPa), etc.].

Table B.1 specifies the concentration of H₂S (in ppm) in the gas phase required to satisfy ‘sour’ condition per ANSI/NACE MR0175/ISO 15156 requirement (PH₂S ≥ 0.05psia) at different equipment pressure rating:

<table>
<thead>
<tr>
<th>System Design Pressure</th>
<th>10ksi</th>
<th>15ksi</th>
<th>20ksi</th>
<th>25ksi</th>
<th>30ksi</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂S Concentration (ppm)</td>
<td>5</td>
<td>3.3</td>
<td>2.5</td>
<td>2</td>
<td>1.7</td>
</tr>
</tbody>
</table>

For HPHT equipment design, Table B.1 illustrates that the required H₂S concentration to establish ‘sour’ service condition is below the limit for reliable analysis of H₂S concentration. As a result, the evaluation and design of HPHT pressure containing equipment must consider the oilfield environment that contact the equipment surfaces as sour.

Sour service condition is defined by the ANSI/NACE MR0175/ISO 15156 as exposure to oilfield environments that contain H₂S and can cause cracking of materials by mechanisms that include SSC, hydrogen induced stress cracking (HISC), stress oriented hydrogen induced cracking (SOHIC) and galvanically induced hydrogen stress cracking (GIHSC).

The ANSI/NACE MR0175/ISO 15156 guidelines provide environmental limits, based on metallurgical properties, for both carbon and low-alloy steels (Part 2) and corrosion-resistant alloys (CRA) (Part 3) to minimize SSC. The following is an overview of ANSI/NACE MR0175/ISO 15156 requirements:

1) Selecting metallic materials for sour service should involve, as a minimum one or more of the following:
   a) Selecting from a prequalified list in ANSI/NACE MR0175/ISO 15156
   b) Laboratory testing (qualification is covered in ANSI/NACE MR0175/ISO 15156, Part 3, Annex B)
   c) Documented field experience using the criteria described in ANSI/NACE MR0175/ISO 15156
2) Defining the service environment in terms of aggressive species.

3) Documenting material properties that affect cracking and confirming that they meet sour service requirements (e.g. hardness values).

4) Documenting QC of the material.

Data for internally clad carbon steel equipment for sour service should be provided to demonstrate that the option offered provides adequate sour resistance, in the form of appropriate test data and/or documented service experience (consistent with the requirements of ANSI/NACE MR0175/ISO 15156).

ANSI/NACE MR0175/ISO 15156 recognizes the fact that water (as a liquid) is required for the identified cracking mechanisms to occur. Hence, for wells producing only dry gas or dry gas injection wells, resistance of materials or equipment to these cracking mechanisms is not required. However, in such cases the presence of water, even if only for short periods, cannot be totally discounted (e.g., water wetting may occur during process upsets, during start up, or during shut-ins). Therefore, in such cases, the presence of water should be assumed and the designation of the well as 'sour' or otherwise, with respect to SSC resistance, should be based solely on the H$_2$S partial pressure.

Pressure-containing HPHT equipment will also be exposed to production fluids or completion brines at high temperatures and pressures. Due to the highly corrosive nature of these fluids at elevated temperatures and the requirements for high strength due to high pressures, the alloys of choice for containment should either be clad (LAS clad with ERNiCrMo-3 if design strength requirement is satisfied) or corrosion resistant alloys that demonstrate adequate resistance to localized (pitting and crevice) corrosion and SCC. Selected materials should have adequate and proven resistance to localized corrosion and SCC caused by chloride ions in produced fluids.

Alloy qualification for localized corrosion resistance of selected material, if not available, should be performed in accordance to ASTM G48 or ASTM G78 in the actual intended service environments where these alloys will be exposed. The ANSI/NACE MR0175/ISO 15156 standard also gives guidelines on qualification of CRA for SCC resistance in different chloride concentrations brines, partial pressures of H$_2$S, partial pressure of CO$_2$, and temperatures.

**B.2.3 External Subsea Applications: Seawater and CP Exposure**

Materials selected for subsea applications that are not inherently resistance to seawater corrosion should be protected by combination of external coatings and CP.

PREN is an indicator of the inherent resistance of a material to localized (pitting and crevice) corrosion in sea water applications. PREN is a useful measurement in ranking materials.

Higher temperature reduces the alloys’ resistance to localized corrosion in seawater applications. Stainless steels, Ni-based alloys with PREN greater than 40 as well as Titanium show inherent resistance to localized corrosion in seawater.

PREN is calculated by:

\[
PREN = W_{Cr} + 3.3 (W_{Mo} + 0.5W_{W}) + 16W_{N}
\]

Where:

- $W_{Cr}$ is the mass fraction of chromium in the alloy, expressed as a percentage of the total composition;
- $W_{Mo}$ is the mass fraction of molybdenum in the alloy, expressed as a percentage of total composition;
- $W_{W}$ is the mass fraction of tungsten in the alloy, expressed as a percentage of total composition;
- $W_{N}$ is the mass fraction of nitrogen in the alloy, expressed as a percentage of total composition.

PREN values do not necessarily correlate with sulfide stress cracking or stress corrosion cracking resistance.

Materials are normally cathodically protected in subsea applications by an application of a negative potential greater than optimal (-850 mV to -950 mV versus Ag/AgCl/seawater) that can lead to hydrogen embrittlement of martensitic and ferritic...
alloys. Hydrogen embrittlement has also been observed in high strength Ni-based alloys. Well designed and installed CP system will normally protect against the following forms of external attack:

1) General corrosion of carbon and LAS
2) Crevice corrosion (e.g. at threaded and flanged connections). Flange protectors are not necessary and should be avoided
3) Galvanic corrosion at junctions of dissimilar metals
4) Chloride ion SCC of austenitic stainless steels
5) Pitting corrosion of stainless steels

As indicated above, external hydrogen embrittlement due to applied CP is a major cracking mechanism experienced by the industry and service experience has proven that external hydrogen embrittlement can be minimized if:

1) Maximum allowable individual hardness of all grades of carbon and low alloy steel that will be exposed to CP for any amount of time should be 34 HRC
2) Individual maximum weld zone hardness of fabricated equipment items should be 325 HV10, which should render materials inherently resistant to hydrogen embrittlement
3) External coating should not be used to provide primary protection against hydrogen embrittlement (i.e., as substitute for inherently resistant materials, etc.)

Several brittle failures of CRA clad LAS closure welds have been experienced in subsea industry due to hydrogen embrittlement cracking in the fusion zone. This is due to a brittle fusion zone can develop in the CRA - LAS interface. PWHT has been found to exacerbate this problem, especially in the LAS with 0.30 weight percentage and higher nominal carbon content.

B.3 Pressure Controlling

In accordance with API definition, pressure-controlling components (e.g. tubing hangers, actuators, and valve components) control and regulate the movement of pressurized fluids. For HPHT systems exposed to sour service conditions, materials for all major components that are wetted by process fluids should comply with ANSI/NACE MR0175/ISO 15156.

Guidance for material selection for tubing hanger and for an HPHT system sour environment is given below:

1) Materials for tubing hangers should be age-hardened Ni-based alloys listed in ANSI/NACE MR0175/ISO 15656-3
2) Solid CRA tubing hangers are generally recommended because of cost and manufacturing simplicity

B.4 Bolting and Fasteners

B.4.1 Sour Service Application

Bolting and fasteners in sour service should comply with ANSI/NACE MR0175/ISO 15156 if in contact with any concentration of wet H2S, either directly or indirectly, i.e. bolting in items that are not freely vented to atmosphere, such as insulated and buried equipment and bolts inside flange protectors, for which leakage of process stream could subject the equipment to a sour environment, etc. Guidance for different bolting materials is as follows:

1) Austenitic stainless steels should comply with ANSI/NACE MR0175/ISO 15656-3. Austenitic stainless steel bolts and nuts, if required, should be free from cold work and should be solution treated after thread forming as follows:
   a) Bolts should be Class 1A of ASTM A193/A193M [e.g., B8MA (UNS S31600) bolts solution treated after all cold work including thread forming]
b) Nuts should be of the “A” suffix variety of ASTM A194/A194M [e.g., Grade 8MA (UNS S31600) solution treated after all hot or cold working]

2) High strength steels for internal bolting and springs, bellows, and parts of reciprocating compressors should comply with ANSI/NACE MR0175/ISO 15156, if in contact with any concentration of wet H₂S.

B.4.2 External Subsea Applications

Since bolts and fasteners for external subsea applications could be exposed to seawater and CP. The following guidelines based on industry experience should be followed:

1) Carbon and LAS bolting suppliers should comply with API 20E in addition to applicable design and/or quality requirements. Sealing of bolts, bolt holes, and space between flanges from external environment, and use of flange protectors and bolt end caps should be avoided. Use of low alloy bolting subsea is dependent on effective CP. Minimum potential of -700mV (Ag/AgCl/seawater) needs to be achieved on all points of all bolts.

2) CRAs fasteners should be specified for:
   a) Internal components contacted by process fluids
   b) External situations if CP of low alloy materials would be considered inadequate (e.g. shielded locations).

CRAs should be considered for bolts threaded directly into CRA components on case by case basis, taking account of probability of galvanic corrosion. Bolts threaded directly into CRA components should be of matching materials specifications, as far as practical.

B.5 Seals

Elastomer sealing configurations are likely to contain a mixture of metallic materials for packing retainers, etc. (e.g. brass, aluminium bronze, steel etc.). It is important that these regions are not exposed to the produced fluids, such that corrosion is not a concern. The following are guidance based on industry experience on metallic sealing material:

1) Materials for gaskets in ASME Ring-Type Joints (RTJ) should be selected and specified to be lower hardness than flange material.

2) When internal corrosion from transported fluids is expected, CRA gasket material should be specified

3) Type 316 and Alloy 825 with hardness limit of 200 BHN are acceptable

4) If Type 316 and Alloy 825 with hardness limit of 200 BHN are specified, Alloy 625 inlay of ring groove should be specified

5) Depending on the corrosivity of the fluids, wet made joints should have 6Mo or Alloy 625 gaskets

6) Metal to metal seals that may be exposed to seawater without CP should be specified in UNS R0035, UNS R0003, Alloy 625, or Alloy C276

7) For carbon steel hub connectors, low alloy steels (typically AISI 4130 or AISI 4140) compliance with ANSI/NACE MR0175/ISO 15156 may be specified

8) For CRA connectors, high strength CRAs that comply with ANSI/NACE MR0175/ISO 15156 should be specified
Annex C
Material Quality Control
(Normative)

C.1 General

The quality control annex addresses tests recommended to verify that each production lot complies with the applicable design requirements. Table C.1 identifies common QC tests that may be required, identifying the recognized industry standards for performing those tests. Note that the industry standards listed in Table C.1 describe the tests to be performed but do not provide the acceptance standards, which are included in either the design standards or specifications for each component or material of construction.

Table C.1: Industry Standards Applicable to Quality Control Tests

<table>
<thead>
<tr>
<th>Test Type</th>
<th>Low Alloy Steels</th>
<th>Duplex Stainless Steels</th>
<th>Ni-Base Alloys</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical Composition</td>
<td>ASTM A751, ASTM E350, ASTM E1806</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Yield Strength</td>
<td>ASTM A370, ASTM E8, ASTM E21</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tensile Strength</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>% Elongation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>% Reduction in area</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CVN Toughness</td>
<td>ASTM E23, ASTM E399, ASTM A673</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$J_{1C}$, $K_{IC}$, CTOD</td>
<td>ASTM E1290, ASTM E1820</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Microstructural Examination, Grain Size</td>
<td>ASTM E112, ASTM E1382</td>
<td>ASTM E112, DNV RP-F112</td>
<td>ASTM E112, ASTM E1181</td>
</tr>
<tr>
<td>Microstructural Examination, Inclusion Rating</td>
<td>ASTM E45</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Microstructural Examination, Phase Balance</td>
<td>n/a</td>
<td>ASTM E562, ASTM E1245</td>
<td>n/a</td>
</tr>
<tr>
<td>Microstructural Examination, Deleterious Phases</td>
<td>ASTM E45, ASTM E788, ASTM E1122, ASTM E1245</td>
<td>ASTM A923</td>
<td>n/a</td>
</tr>
<tr>
<td>NDE, ET</td>
<td>ASME Sec V, ASTM E309, ASTM E376, ASTM E426, ASTM E566, ASTM E571, ASTM E703</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NDE, MT</td>
<td>ASME Sec V, ASTM A275, ASTM E709, ASTM E1444</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>NDE, PT</td>
<td>ASME Sec V, ASTM E165, ASTM E1417</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NDE, RT</td>
<td>ASME Sec V, ASTM E94, ASTM E999, ASTM E1815</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NDE, UT</td>
<td>ASME Sec V, ASTM A388, ASTM E213, ASTM E273, ASTM E2375</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corrosion Testing</td>
<td>n/a</td>
<td>ASTM G48</td>
<td>n/a</td>
</tr>
<tr>
<td>Positive Material Identification</td>
<td>API RP 578</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Specific QC testing requirements for each component or production lot should be described in a technical specification. In order to facilitate QC activities on the shop floor during production, the specification requirements are typically summarized in the form of an inspection and testing plan (ITP), which identifies:

1) Each of the QC tests that will be required for the component or production lot.

2) The location(s) and number of specified non-destructive tests.
3) The location(s), orientation(s), and number of specimens specified for destructive tests.

4) The industry standard describing how each of the tests should be performed along with any additional required information.

5) The acceptance standards for each of the required QC tests.

6) Any options for additional testing for situations in which the initial test result(s) do not satisfy the acceptance standards.

C.2 Process Control

Qualification of a manufacturing process should be based upon the concept that the process is described in a manufacturing procedure specification (MPS) that identifies certain essential variables that determine the properties of components manufactured by that process. The MPS should also identify the permitted range of each essential variable.

The manufacture of production components must be maintained within the acceptable range of each essential variable for the qualification to be credible. The requirements and acceptance standards for QC testing rely upon the assurance that a manufacturing process is controlled within the range of parameters that reliably produce acceptable components.

C.3 Acceptance Standards

Applicable industry standards or specifications should define the acceptance criteria.

C.4 Chemical Composition

The chemical composition of metallic materials may be determined from a sample of molten metal collected before the metal is cast and solidified (cast or heat analysis) or from a sample of metal taken from a solidified product form (i.e. product, check, or verification analysis, etc.). Industry standards address various methods and procedures for determining chemical composition.

The technical specification and subsequent ITP should state:

1) Whether the chemical composition requirement will be based on heat analysis, check analysis or both.

2) The elements that will be determined and the allowable ranges, either by listing this information or by reference to industry standards that contain these requirements.

C.5 Mechanical Properties

Verification that mechanical properties of production-lots of components meet the properties assumed during design and verification is critical. Verification measures include the following:

1) Hardness Testing: Hardness testing is a non-destructive screening method to verify compliance with codes and materials specifications. The technical specification and subsequent ITP should identify the hardness testing apparatus (e.g., Brinell, Rockwell, and Vickers) and reporting scale that is required or scales that are permitted, along with the required range of acceptable hardness. The ITP should also identify the hardness testing location(s) on a component along with the testing frequency. In case of dispute, Rockwell C scale should be the arbitrator method.

2) Tension Testing: For round specimens only, standard tension tests performed at room temperature provide yield strength, tensile strength, elongation (%), and reduction in area (%) for comparison with specified values. Typically, minimum values are specified for each of these mechanical properties, but a range of minimum and maximum values may be specified for yield and tensile strength to assure satisfactory weldability and/or resistance to environmental cracking.

Tension tests at the anticipated maximum operating temperature may be required for applications with maximum temperature in excess of 250°F. The yield and tensile strength requirements for elevated-temperature tension tests should align with the assumptions for de-rating of strength at elevated temperatures.
3) Toughness Testing: Toughness tests evaluate the resistance of a material to fracture under load. Carbon and low-alloy steels exhibit the phenomena described as a transition from ductile-to-brittle fracture as the metal temperature is reduced. Consequently, toughness testing of carbon and low-alloy steels should be performed at the lowest anticipated service temperature (LAST) or minimum design metal temperature (MDMT) or colder. In some situations, the test temperature is offset a specified amount below LAST or MDMT to account for the tendency for scatter in toughness testing results.

Metals with austenitic microstructure ordinarily do not exhibit the transition from ductile-to-brittle fracture, but these metals are also toughness tested at LAST or MDMT, with or without temperature offset. Some CRA, most notably duplex-stainless steels and some precipitation-hardened alloys, may be toughness tested at temperatures significantly colder than LAST or MDMT in order to evaluate the response of the microstructure to heat treatment. Abnormally low toughness at the specified test temperature may be an indication that the microstructure contains deleterious phases. Candidate test procedures include:

a) Charpy V-notch Impact Tests: The Charpy V-notch (CVN) impact test is widely employed to evaluate the toughness of metals. The most common CVN test application is testing of a set of three specimens machined from a coupon from the specified location in a given orientation. Each CVN test specimen can yield: 1) energy absorbed during fracture of the specimen, 2) fracture appearance of the resulting fracture, and 3) lateral expansion of the specimen at the notch. CVN requirements are typically specified as the average of the individual results from a set of three (3) specimens, but a minimum value for an individual specimen from the set of three may also be specified.

CVN data is not directly applicable for failure assessment evaluation, although correlations between CVN and other toughness parameters are available (e.g., in API 579-1/ASME FFS-1, BS 7910) and can be used in FM analyses. CVN testing should be performed during “First Article Qualification” of critical forgings for correlation with the FT data. CVN testing performed during QC of production lots may then be related to target FT results.

b) J\textsubscript{IC}, K\textsubscript{IC} or CTOD: FT tests such as J\textsubscript{IC}, K\textsubscript{IC}, or CTOD are not generally employed for QC purposes due to time and cost to prepare and perform the tests. However, they can be supplemental requirements upon request by the purchaser.

C.6 Microstructure

Semi-quantitative methods are available to characterize the microstructure of a metal in ways that may be useful for QC to determine if a manufacturing process is in control. Characterizing the microstructure of carbon and low-alloy steel is different from characterizing the microstructure of corrosion-resistant alloys, as follows:

1) Carbon and Low-alloy Steels: The prior austenite grain size and inclusion density and shape can have a significant influence on the toughness of carbon and low-alloy steels. Consequently, comparing the grain size and inclusion population of production components with the grain size and inclusion population of qualification test pieces can provide useful information for determining if the manufacturing process is in control.

a) Prior Austenite Grain Size: The prior austenite grain size should be determined according to one of the ASTM E112 methods. Fine grain practice, ASTM 5 or smaller, may be specified, but fine prior austenite grain size decreases hardenability of carbon and low-alloy steels. Consequently, assuring the required strength and toughness at the mid-section of heavy wall forgings may be more important than achieving fine grain size.

b) Inclusion Rating: The rating of inclusion density and shape as per ASTM E45 evolved as a manual comparison of metallurgical specimens with standard photomicrographs of different levels of inclusion density and shape. Development of automated image analysis facilitated evolution of methods to allow software to automate the comparison of metallurgical specimens with standards levels of inclusion density and shape. Inclusion ratings that comply with the acceptance standards identified in the specification and ITP tend to indicate that the melting practice was in control.

2) CRAs: Evaluations of the microstructure of duplex stainless steels and precipitation-hardened nickel-base alloys are discussed in this section.

a) Duplex Stainless Steels: Duplex stainless steels employed in subsea system include two (2) general classes with 22% and 25% chromium, respectively. Each of these classes includes multiple alloys with similar strength and corrosion resistance.
1) Phase Balance: The microstructure of duplex stainless steels is nominally 50% ferrite and 50% austenite, but practical production requires a tolerance around this nominal phase balance. The component specification and ITP should identify the procedure used to determine phase balance and the acceptance standard. Manual point counting as per ASTM E562 on prepared metallurgical specimens is widely employed for estimating the phase balance of duplex stainless steels. Automatic image analysis may also be employed to estimate the phase balance of duplex stainless steels. The component specification and ITP should identify the required magnification, the number of fields to be examined, and the number of points in each field.

Increasing the number of fields examined and/or the number of points in each field tends to improve the precision of the phase balance estimate. Consequently, a component specification and ITP should explicitly permit increasing the number of fields examined and/or the number of points in each field, especially for microstructures that are near the acceptance standard limit.

Portable instruments for evaluating the phase balance of duplex stainless steels are available. These instruments evaluate the ratio of magnetic ferrite and nonmagnetic austenite based on the magnetic properties of the location immediately under the probe. The condition of the surface (roughness, radius of curvature, cold work, pickling, and deleterious phases) under the probe can influence the probe reading. While these instruments may be less precise than point counting on prepared metallurgical specimens, a trained inspector can make multiple readings at various locations on a complex components in a relatively short time.

2) Grain Size and Austenite Spacing: Duplex stainless steel bar, plate, and forgings tend to have an elongated grain structure, which complicates determination of the average size of ferrite and austenite phases. DNV RP-F112 Design of Duplex Stainless Steel Subsea Equipment Exposed to Cathodic Protection states that the average spacing between the austenite grains is more significant than grain size of the ferrite and austenite for evaluating resistance to HISC.

3) Deleterious Third-Phases: ASTM A923 offers these three alternative methods for evaluating duplex stainless steels for deleterious third phases:

   a) Test Method A: Sodium Hydroxide Etch Test for Classification of Etch Structures of Duplex Stainless Steels,

   b) Test Method B: Charpy Impact Test for Classification of Structures of Duplex Stainless Steels, or

   c) Test Method C: Ferric Chloride Corrosion Test for Classification of Structures of Duplex Stainless Steels.

   Test Method B may be the most unambiguous method to assess deleterious third phases in duplex stainless steels.

3) Nickel-Based Alloys

   a) Grain Size: Determining the average grain size of nickel-base alloys with a large distribution of grain sizes in a component according to ASTM E112 may misrepresent its appearance. Consequently, ASTM E1181 Standard Test Methods for Characterizing Duplex Grain Sizes may be specified for nickel-base alloys. ASTM E1181 identifies the following three conditions of duplex grain sizes:

      1) Cross-section condition
      2) Necklace condition
      3) Banding condition

As a topological duplex grain size, industry standards and specifications may characterize a topological duplex grain size as undesirable for applications that are more critical.

Large grain sizes, which may be present in nickel-base alloys, tend to disperse ultrasonic signals employed for volumetric inspection of heavy wall components. Signal dispersion may interfere with interpretation of reflected signals. Topological duplex grain sizes may cause additional interference with interpretation.
b) Deleterious Phases: Deleterious phases are secondary phases present in the microstructure of an alloy that have a negative effect on the desired mechanical properties, toughness, or corrosion resistance of the alloy. The microstructure should be free from continuous networks of secondary phases along grain boundaries except for individual, isolated grains that are not representative of the bulk microstructure.

C.7 NDE Methods

Multiple methods of NDE may be employed to detect flaws or indications in components. Some NDE methods are only suitable for examining the surface of components while other NDE methods are suitable for volumetric examination of the interior of components. NDE personnel considered for the performance of these examinations should have the necessary experience, training, certifications, and qualifications. NDE shall be performed in accordance with written procedures that include acceptance criteria. All NDE results (including visual) shall be documented and be traceable to the item examined.

1) Surface NDE: Surfaces of components are typically examined to identify indications that penetrate the surface. Reliable surface inspection requires that the surface being inspected be clean and free of debris, well lighted, and oriented for convenient examination. Rough surfaces can mask surface indications as well as cause artifacts that are not indications.

a) Visual Examination: Detailed visual examination of the entire surface of components by trained and experienced inspectors is one of the most cost-effective NDE methods. Reliable surface inspections require that the surface being examined be clean, free of debris and foreign matter, be well lighted (1000-2000 Lux recommended), and oriented for convenient examination. The equivalent acceptance standard should be applied to visual examination as with magnetic particle testing (MT), penetrant (dye) testing (PT) and eddy current testing (ET).

b) Eddy Current Testing: Eddy current testing is performed by inducing small electrical currents (eddy currents) into the metallic material by using alternating magnetic fields. The test detects changes in electrical and magnetic properties caused by surface and near surface discontinuities, hardness, and chemistry. ET should be performed by operators with minimum of Level II qualification per BS EN 473 and ASNT SNT TC-1A standards. An established written operational standard for performing eddy current examination should be approved by an inspector with corresponding credentials equivalent to or greater than Level III.

c) Magnetic Particle Testing: MT is applicable only to ferromagnetic materials. MT examinations should be performed on all accessible surface areas, and should be performed prior to and after final heat treatment. All machined surfaces prepared for weld cladding should require magnetic particle examination prior to welding. MT examinations of base metal areas should contain no relevant indications. All magnetic particle examinations should use the AC wet fluorescent technique and should be conducted in accordance with ASTM E1444. Magnetic particle system reliability demonstrations should be conducted in accordance with ASTM E709 prior to the examination of production components after each shift change and or change in operators.

d) Penetrant (dye) Testing: PT is applicable for surface examination of both ferromagnetic and nonmagnetic materials. Penetrant examinations of all austenitic CRA surfaces and other nickel based alloys should use the fluorescent penetrant process. All penetrant consumables (including cleaner, emulsifies and developers) should be certified to contain less than 1% weight of sulfur and halogen concentrations. The control of contaminants should be accordance with ASME Section V, Article 6 Paragraph T-641.

A PSM-5 P Tam panel test should be conducted prior to the examination of production components, and the test should be able to detect all file (5) crack centers adequately whose dimensions range from A to E listed below. This test should be conducted and documented with each change in consumable batch numbers.

<table>
<thead>
<tr>
<th>Batch</th>
<th>Dimensions</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>0.015 - 0.031 (0.38 - 0.79mm)</td>
</tr>
<tr>
<td>B</td>
<td>0.046 - 0.062 (1.17 - 1.57mm)</td>
</tr>
<tr>
<td>C</td>
<td>0.075 - 0.093 (1.91 - 2.36mm)</td>
</tr>
<tr>
<td>D</td>
<td>0.125 - 0.171 (3.18 - 4.34mm)</td>
</tr>
<tr>
<td>E</td>
<td>0.180 - 0.250 (4.57 - 6.35mm)</td>
</tr>
</tbody>
</table>

2) Volumetric NDE: Volumetric NDE is primarily used to examine a materials or components internal integrity. Volumetric examinations may also aid in the detection of surface connected discontinuities as well.
a) Radiographic Testing: Radiographic testing (RT) can be practical for volumetric NDE of subsea components with relatively thin wall thickness. For high pressure high temperature applications, radiography is not the recommended NDE technique for volumetric examinations. Radiographic contrast and sensitivity becomes less as part thickness increases and higher energy sources are used to radiograph thicker sections of a component.

RT is more useful for detection of relatively large volumetric discontinuities than planar flaws. Planar flaws must be aligned parallel with the radiation beam in order to produce an indication on the imaging medium. As flaw angularity increases from the beam of radiation, the flaws (PoD) decrease.

Acceptance standards for RT inspection are limited to workmanship based acceptance criteria's; this is due to radiography being able to provide only qualitative two (2) dimensional flaw data. RT images of discontinuities can allow an estimation of length and width of flaws but do not provide useful information in regards to depth or cross sectional area of a flaw.

b) Ultrasonic Testing: Ultrasonic testing (UT) is the preferred NDE method for volumetric examination. Ultrasonic examination should be conducted in accordance with appropriate industry specifications (Table C.1) and acceptance criteria should be commensurate with design requirements.

C.8 Corrosion Testing

Corrosion testing is more frequently employed for qualification of a material or manufacturing process than during QC of production components. Corrosion testing may be required on a production basis for certain alloys prone to localized corrosion due to secondary phases and precipitates.

C.9 Positive Material Identification

Positive material identification (PMI) is typically one of the last quality control tests performed prior to acceptance of a manufactured component, even though PMI should also be performed during receipt of raw material and in some situations between selected manufacturing steps.

PMI employs an instrument designed specifically for the task of evaluating the quantity of the major alloy elements in raw material or a component and comparing that information with the range of composition specified for common alloys.

The two (2) basic types of PMI instruments are Portable X-ray Fluorescence and Portable Optical Emission Spectrometry. Results from these two (2) instruments are typically considered to be semi-quantitative because the precision of portable PMI instruments is less than the precision of laboratory instruments and techniques. Consequently, PMI is not a substitute for conventional chemical analysis discussed in Annex C.3.
Annex D
Technical References
(Normative)

The latest edition/addenda of the following technical references are applicable to this technical report, at publication date:

- ANSI/NACE MR0175/ISO 15156-3, Petroleum and natural gas industries - Materials for use in H₂S-containing environments in oil and gas production - Part 3: Cracking-resistant CRAs (corrosion-resistant alloys) and other alloys
- API 579-1/ASME FFS-1, Fitness-For-Service
- API Recommended Practice 17G, Recommended Practice for Completion/Workover Risers
- API Recommended Practice 17N, Recommended Practice for Subsea Production System Reliability and Technical Risk Management
- API Recommended Practice 17Q, Subsea Equipment Qualification - Standardized Process for Documentation
- API Recommended Practice 1111, Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limited State Design)
- API Specification 6AB, Specification for 30,000 psi Flanged Wellhead Equipment, Withdrawn
- API Specification 14A, Specification for Subsurface Safety Valve Equipment
- API Specification 16A, Specification for Drill-through Equipment
- API Specification 16C, Specification for Choke and Kill Systems
- API Specification 20B, Specification for Open Die Forgings for the Petroleum and Natural Gas Industry
- API Specification 20C, Closed Die Forgings for Use in the Petroleum and Natural Gas Industry
- API Specification 20E, Alloy and Carbon Steel Bolting for Use in the Petroleum and Natural Gas Industries
- API Technical Report TR 6J1, Elastomer Life Estimation Testing Procedures
- ASM Handbook, Volume 1, Properties and Selection: Irons, Steels and High Performance Alloys
- ASM Handbook, Volume 2, Properties and Selection: Nonferrous Alloys and Special-Purpose Materials
- ASME B31.3, Process Piping
- ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids
- ASME B31.8, Gas Transmission and Distribution Piping Systems
- ASME BPVC Section II, Part D, Properties Materials
- ASME BPVC Section V, Nondestructive Examination
- ASME BPVC Section VIII, Division 2, Rules for Construction of Pressure Vessels - Alternative Rules
- ASME BPVC Section VIII, Division 3, Alternative Rules for Construction of High Pressure Vessels
- ASME BPVC Section IX, Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators
- ASNT SNT TC 1A, Recommended Practice for Personnel Qualification and Certification in Nondestructive Testing
- ASTM A193, Standard Specification for Alloy-Steel and Stainless Steel Bolting for High Temperature or High Pressure Service and Other Special Purpose Applications
- ASTM A275, Standard Practice for Magnetic Particle Examination of Steel Forgings
- ASTM A370, Standard Test Methods and Definitions for Mechanical Testing of Steel Products
- ASTM A388, Standard Practice for Ultrasonic Examination of Steel Forgings
- ASTM A751, Standard Test Methods, Practices, and Terminology for Chemical Analysis of Steel Products
- ASTM A833, Standard Practice for Indentation Hardness of Metallic Materials by Comparison Hardness Testers
- ASTM A923, Standard Test Methods for Detecting Detrimental Intermetallic Phase in Duplex Austenitic/Ferritic Stainless Steels
- ASTM E8, Standard Test Methods for Tension Testing of Metallic Materials
- ASTM E10, Standard Test Method for Brinell Hardness of Metallic Materials
- ASTM E18, Standard Test Methods for Rockwell Hardness of Metallic Materials
- ASTM E45, Standard Test Methods for Determining the Inclusion Content of Steel
- ASTM E55, Standard Practice for Sampling Wrought Nonferrous Metals and Alloys for Determination of Chemical Composition
- ASTM E94, Standard Guide for Radiographic Examination
- ASTM E111, Standard Test Method for Young’s Modulus, Tangent Modulus, and Chord Modulus
- ASTM E112, Standard Test Methods for Determining Average Grain Size
- ASTM E140, Standard Hardness Conversion Tables for Metals Relationship Among Brinell Hardness, Vickers Hardness, Rockwell Hardness, Superficial Hardness, Knoop Hardness, and Scleroscope Hardness
- ASTM E165, Standard Practice for Liquid Penetrant Examination for General Industry
- ASTM E213, Standard Practice for Ultrasonic Testing of Metal Pipe and Tubing
- ASTM E273, Standard Practice for Ultrasonic Testing of the Weld Zone of Welded Pipe and Tubing
- ASTM E309, Standard Practice for Eddy-Current Examination of Steel Tubular Products Using Magnetic Saturation
- ASTM E376, Standard Practice for Measuring Coating Thickness by Magnetic-Field or Eddy-Current (Electromagnetic) Testing Methods
- ASTM E399, Standard Test Method for Linear-Elastic Plane-Strain Fracture Toughness $K_{IC}$ of Metallic Materials
- ASTM E426, Standard Practice for Electromagnetic (Eddy-Current) Examination of Seamless and Welded Tubular Products, Titanium, Austenitic Stainless Steel and Similar Alloys.
- ASTM E569, Standard Practice for Acoustic Emission Monitoring of Structures During Controlled Simulations.
- ASTM E571, Standard Practice for Electromagnetic (Eddy-Current) Examination of Nickel and Nickel Alloy Tubular Products.
- ASTM E606, Standard Practice for Strain-Controlled Fatigue Testing
- ASTM E647, Standard Test Method for Measurement of Fatigue Crack Growth Rates
- ASTM E709, Standard Guide for Magnetic Particle Testing
- ASTM E999, Standard Guide for Controlling the Quality of Industrial Radiographic Film Processing
- ASTM E1141, Standard Practice for the Preparation of Substitute Ocean Water
- ASTM E1181, Standard Test Methods for Characterizing Duplex Grain Sizes
- ASTM E1245, Standard Practice for Determining the Inclusion or Second-Phase Constituent Content of Metals by Automatic Image Analysis
- ASTM E1417, Standard Practice for Liquid Penetrant Testing
- ASTM E1444, Standard Practice for Magnetic Particle Testing
- ASTM E1473, Standard Test Methods for Chemical Analysis of Nickel, Cobalt, and High-Temperature Alloys
- ASTM E1806, Standard Practice for Sampling Steel and Iron for Determination of Chemical Composition
- ASTM E1815, Standard Test Method for Classification of Film Systems for Industrial Radiography
- ASTM E2714, Standard Test Method for Creep-Fatigue Testing
- ASTM G46, Standard Guide for Examination and Evaluation of Pitting Corrosion
- ASTM G48, Standard Test Methods for Pitting and Crevice Corrosion Resistance of Stainless Steel and Related Alloys by Use of Ferric Chloride Solution
- BS 7910, Guide to methods for assessing the acceptability of flaws in metallic structures
- BS EN 473, Non-destructive testing - Qualification and certification of NDT personnel - General principles
- DNV-RP-C203, Fatigue Design of Offshore Steel Structures
- DNV-RP-D101, Structural Analysis of Piping Systems
- DNV-RP-F112, Design of Duplex Stainless Steel Subsea Equipment Exposed to Cathodic Protection
- ISO 6892-1, Metallic materials - Tensile testing - Part 1: Method of test at room temperature
- ISO 6892-2, Metallic materials - Tensile testing - Part 2: Method of test at elevated temperature
- ISO 13879, Petroleum and Natural Gas Industries - Content and Drafting of a Functional Specification
- ISO 13880, Petroleum and Natural Gas Industries - Content and Drafting of a Technical Specification
- NACE TM0177, Laboratory Testing of Metals for Resistance to Sulfide Stress Cracking and Stress Corrosion Cracking in H2S Environments
- NACE TM0198, Slow Strain Rate Test Method for Screening Corrosion-Resistant Alloys for Stress Corrosion Cracking in Sour Oilfield Service
- NORSOK M-710, Qualification of non-metallic sealing materials and manufacturers