High-pressure High-temperature Design Guidelines

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Introduction

This technical report is the first of several editions to serve as a design guidelines for high-pressure high-temperature (HPHT) equipment, specifically for subsea applications. This first edition is offered in hopes of bringing relevant state-of-the-art practices to address emerging projects while the task group continues to work on specific problems requiring additional time to research and resolve issues such as welding, CRA cladding, QA, sensors, etc.

This document is not intended to be a standalone specification or standard. Rather it is presented as a technical guidance document so that specifications, standards, and recommended practices may reference this document, in part or in total, to augment their operating scope greater than 15,000 psi (103.43 MPa) and/or greater than 350 °F (177 °C) wellbore conditions as proffered by API 1PER15K-1.

It is necessary that users of this technical report be aware that additional or different requirements which can better suit the demands of a particular service environment, the regulations of a jurisdictional authority or other scenarios not specifically addressed in this technical report, may be applied as required. This document is a technical report and it is not intended to replace sound engineering judgment.

In the development of this technical report, the items below are recognized as on-going work for resolution. Many will require additional discussion and debate, between governing API and ASME standards and their associated design/manufacturing processes. Rather than wait and hold up the publication of the first edition of this technical report, until everything is resolved, the task group elected to release the work it has accomplished so far, and alert the reader to the work still to be resolved; highlighting that there could be changes to the technical report in subsequent editions.

1) Materials QA/QC differences between API, and ASME standards: The task group acknowledges that the QA/QC requirements found in ASME and API standards are not aligned, and additionally, may not be aligned between API sub-committees. It is beyond the scope of this technical report to close this gap. As further work is conducted and information comes to light, it is envisioned that the gaps will progress to convergence. It is recommended that these gaps be documented in a FMECA as input to the verification process, and included in the development of a documented design validation program to address the gap.

2) Inclusion of external loading: The task group has authored this technical report to provide specific guidance to utilize design codes which are applicable for the inclusion of external loading.

3) Where the design codes (e.g. ASME *BPVC* Section VIII, Div. 2 and Section VIII, Div. 3) are referenced in this technical report for subsea applications, these design codes and this technical report provide guidance for applicable loads, static, dynamic, and cyclic.

4) Hydrostatic body test pressures: API Specifications typically require a hydrostatic body test on single-equipment units and this technical report recommends different minimum hydrostatic test pressures depending on the design verification method chosen. This could result in two or more components being assembled where ASME Section VIII, Div. 2 component(s), tested to 1.5xRWP, combined with ASME Section VIII, Div. 3 component(s), tested to 1.25xRWP, into an assembly/system. However, system integration testing (SIT) of an assembly/system is not in the scope of this technical report.

5) Application of “Extreme” and “Survival” loading conditions: The task group acknowledges differences between API and ASME *BPVC* loading conditions and allowable limits for these loading conditions. Currently, it is the task group’s opinion that there is insufficient correlation to provide specific recommendations of the treatment and acceptance criteria of these load cases. It is recommended that, if these loading conditions are present during HPHT applications they should be documented in the FMECA process, inputted to the design verification process, and included in the design validation program, as needed to address this gap.

As a cautionary note: It should be understood that some of the text on design methodology, material performance data, and qualification/validation requirements published in this first edition may be modified (i.e. changed, added, deleted, etc.) as continuing topics are resolved and as new information and technology become available in subsequent editions.

High-pressure High-temperature Design Guidelines

1 Scope

1.1 Scope of Technical Report

The scope of this technical report is to provide design guidelines for oil and gas subsea equipment utilized in high-pressure high-temperature (HPHT) environments (refer to 3.1.16). 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 psia [15 ksi, 103.43 MPa] or a temperature rating greater than 350 °F (177 °C);

2) the maximum anticipated surface pressure including shut-in tubing pressure is greater than 15,000 psia [15 ksi, 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 outside the scope of this technical report.

This technical report is intended to serve as a general design guideline for HPHT application. Other subsea task groups and subcommittees may elect to adopt a portion or all of the presented guidelines for HPHT application, subject to their component hardware and application-related design constraints.

1.2 Application

The scope of this technical report is limited to equipment and components identified in API documents that focus on subsea production equipment while addressing one or a combination of the following loading conditions:

— internal and external pressure;

— ambient and elevated operating temperatures;

— static and dynamic mechanical loads;

— other pressure/temperature induced loadings.

This technical report is intended to provide design guidelines for pressure-containing components, seals and fastener components that come in contact with or are immediately adjacent to wellbore fluids operating at HPHT conditions. Intra-field piping systems (e.g. steel flowline and pipeline jumpers, manifold piping, valving and connectors, intervention riser equipment) are 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 does not cover:

— flexible pipes (bonded and unbonded);

— oil-country tubular goods (OCTG) for drilling or completing wells;

— downstream pipeline or production riser designs;

— downhole component hardware that may be subject to additional application-related design constraints;

— equipment covered by other API publications that specifically address HPHT applications;

— structural members or ancillary equipment associated with HPHT hardware but not working in close proximity to the HPHT environment;

— Brittle materials (i.e. essentially no plastic deformation prior to failure, etc.).

1.3 API 17TR8 Main Topics

The main topics for this technical report are categorized as:

1) Design Verification: The design verification process focuses on analytical methods. The specified requirements include the mechanical integrity, life cycle, and other service requirements.

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 Bolting/Fasteners: The seals and bolting/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 integrity 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).

5) Hydrostatic Test for HPHT Equipment: The hydrostatic test sections provide guidance on the applicable hydrostatic test pressure based on the application of the design standard.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*, Twentieth Edition, October 2010

API Specification 17D, *Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment*, Second Edition, May 2011

API Specification 20E, *Alloy and Carbon Steel Bolting for Use in the Petroleum and Natural Gas Industries*, First Edition, August 2012

API Standard 6X, *Design Calculations for Pressure-containing Equipment*, First Edition, March 2014

ANSI/ASME B1.1 [1,2], *Unified Inch Screw Threads*, 2003 Edition

ASME *BPVC* Section VIII , *Rules for Construction of Pressure Vessels Division 2—Alternative Rules*, 2013 Edition

1 American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, New York 10036, www.ansi.org.
2 ASME International, 2 Park Avenue, New York, New York 10016-5990, www.asme.org.

ASME *BPVC* Section VIII, *Rules for Construction of Pressure Vessels Division 3—Alternative Rules for Construction of High Pressure Vessels,* 2013 Edition

NACE MR0175 [3], *Petroleum and natural gas industries—Materials for use in H2S-containing environments in oil and gas production—Parts 1, 2, and 3*, 2009

3 Terms, Definitions, Acronyms, Abbreviations, and Symbols

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1
autofrettage
A process for producing a system of favorable residual stresses in a thick-wall vessel by pressurizing to produce plastic deformation in part or all of the wall thickness.

NOTE Autofrettage typically refers to a phenomenon where the material at the internal bore of a pressurized vessel experiences localized stresses exceeding the material's yield strength (YS) while material further from the bore is stressed below the yield strength.

3.1.2
barrier
Practice or component forming part of a pressure-containing or pressure-controlling envelope which is designed to prevent unintentional flow of produced or injected fluids, particularly to the external environment.

3.1.3
barrier element
A component that serves as part of a pressure-containing or pressure-controlling envelope.

3.1.4
barrier envelope
A series of barrier elements which, when linked together, act as a pressure-containing vessel or envelope, preventing leakage of well fluids.

3.1.5
cast or heat analysis
[ladle analysis (obsolete)]
Chemical analysis as representative of a heat of metal as reported to the purchaser and determined by analyzing a test sample obtained from the molten metal or product of remelted ingot, for the elements designated in a specification.

3.1.6
check analysis
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.

3.1.7
chemical analysis
Analysis of the semi-finished or finished product, usually for the purpose of determining conformance to the specification requirements.

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3 NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77084-4906, www.nace.org.

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.

3.1.8
corrosion-resistant alloy
CRA
Nonferrous-based alloy for which any one or the sum of the specified amount of the elements titanium, nickel, cobalt, chromium, and molybdenum exceeds 50 % mass fraction.

NOTE This definition follows API 6A which is different from that in NACE MR0175/ISO 15156 (see Part 2).

3.1.9
corrosion-resistant material
CRM
Ferrous or non-ferrous alloy that is more corrosion resistant than low-alloy steels.

NOTE This term includes: CRAs, duplex, austenitic, and martensitic stainless steels.

3.1.10
closure bolting
Threaded fasteners used to assemble wellbore pressure-containing components or join end or outlet connections.

EXAMPLE Studs, nuts, bolts, and cap screws, etc.

3.1.11
critical bolting
Threaded fasteners and closure bolting, identified as high-risk components (i.e. loss of structural integrity or pressure containment).

EXAMPLE Studs, nuts, bolts, and cap screws, etc.

3.1.12
design validation
Process of proving a design by testing to demonstrate conformity of the product to design requirements.

NOTE Design validation includes one or more of the following:

a) prototype tests;

b) functional and/or operational tests of production products;

c) tests specified by industry standards and/or regulatory requirements;

d) field performance tests and reviews.

3.1.13
design verification
Process of examining the result of a given design or development activity to determine conformity with specified requirements.

NOTE Design verification includes one or more of the following:

a) confirming the accuracy of design results through the performance of alternative calculations;

b) review of design output documents;

c) comparing new designs to similar proven designs.

3.1.14
fracture toughness
Property of a material that measures the resistance-to-failure resulting from crack propagation.

3.1.15
functional specifications
Document generated by the user/purchaser that specifies the design parameter requirements and operating conditions, as appropriate.

3.1.16
high-pressure high-temperature
Reference to wells with a potential pressure greater than 15,000 psia (103.43 MPa), or with a potential temperature greater than 350 °F (177 °C), up to 550 °F (288 °C), measured at the mudline.

3.1.17
hydrogen-assisted cracking
A hydrogen embrittlement mechanism in CRAs promoted by generation/adsorption of atomic hydrogen due to exposure to seawater and cathodic protection and other conditions.

3.1.18
hydrogen-induced cracking
A hydrogen embrittlement mechanism in duplex stainless steels promoted by generation/adsorption of atomic hydrogen due to exposure to seawater and cathodic protection.

3.1.19
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.

3.1.20
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.

3.1.21
pressure absolute (psia)
Pressure measured relative to absolute zero pressure. The internal pressure that the equipment is designed to contain and/or control, measured in “psia”.

3.1.22
pressure-containing
Part exposed to wellbore fluids, whose failure to function as intended results in a release of wellbore fluid to the environment.

3.1.23
pressure-controlling
Part that is intended to control or regulate the movement of pressurized fluids.

3.1.24
primary barrier
First component that prevents flow from a source.

3.1.25
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.

3.1.26
secondary barrier
Second component that prevents flow from a source.

3.1.27
shakedown
A phenomenon caused by cyclic loads or cyclic temperature distributions which produces plastic deformations in some regions of the component when the loading or temperature distribution is applied; but upon removal of the loading or temperature distribution, only elastic primary and secondary stresses are developed in the component, except in small areas associated with local stress (strain) concentrations.

3.1.28
stainless steel
Steel containing more than 11 % mass fraction chromium to render the steel corrosion-resistant.

NOTE Other elements may be added to secure specific properties.

3.1.29
stress cycle(s)
Condition in which the stress goes from an initial value to a maximum value, then to a minimum value, and then returns to the initial value, or vice versa.

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

3.1.30
tensile strength (ultimate)
The maximum load before failing or breaking divided by the original cross-sectional area.

3.1.31
yield strength
Stress level, measured at room temperature and elevated temperature, at which material plastically deforms and does not return to its original dimensions when the load is released.

NOTE Yield strengths specified in this technical report are the 0.2 % offset yield strength in accordance with ASTM A370 or ISO 6892-1.

3.2 Acronyms and Abbreviations

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

AE	acoustic emission
AISI	American Iron and Steel Institute
ANSI	American National Standards Institute
API	American Petroleum Institute
ASM	American Society for Metals
ASME	American Society of Mechanical Engineers
ASNT	American Society for Nondestructive Testing

ASTM	American Society for Testing and Materials
BPVC	(ASME) *Boiler and Pressure Vessel Code*
BS	British Standards
BSL	bolt specification level
CCT	critical crevice temperature
CP	cathodic protection
CPT	critical pitting temperature
C-R	circumferentially oriented specimen with a radial flaw
CRA	corrosion-resistant alloy
CRM	corrosion-resistant material
CTOD	crack tip opening displacement
CVN	charpy V-notch
DCB	double cantilever beam
DNV	Det Norske Veritas
e-N	strain-cycle curves
EAC	environmentally assisted cracking (service environment)
EHE	external hydrogen embrittlement
ET	eddy current testing
FCGR	fatigue crack growth rate
FEA	finite element analysis
FMEA	failure modes and effects analysis
FMECA	failure modes, effects and criticality analysis
FM	fracture mechanics
FT	fracture toughness
GHSC	galvanically-induced hydrogen stress cracking
HAC	hydrogen-assisted cracking
HAZOP	hazard and operability
HIC	hydrogen-induced cracking
HISC	hydrogen-induced stress cracking
HP	high-pressure
HPHT	high-pressure high-temperature
HT	high-temperature
HRC	hardness Rockwell C
ISO	International Organization for Standardization
ITP	inspection and test plan
kPa	kiloPascal
ksi	1000 pounds per square inch
LAS	low-alloy steel

LAST	lowest anticipated service temperature
L-C	longitudinally oriented specimen with a circumferential flaw
LRFD	load resistance factor design
MDMT	minimum design metal temperature
MPS	manufacturing procedure specification
MPa	megaPascal
MT	magnetic particle testing (also refer to as MPI)
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination
NIST	National Institute of Standards and Technology
OCTG	oil-country tubular goods
PMI	positive material identification
PoD	probability of detection
ppm	parts per million
PR	performance requirements (validation)
PREN	pitting resistance equivalent number
psia	pounds per square inch absolute
PSL	product specification level
PT	penetrant (dye) testing
PWHT	post weld heat treatment
QA	quality assurance
QC	quality control
QRA	quantitative risk assessment
RT	radiographic testing
RWP	rated working pressure
RGD	rapid gas decompression
RTJ	ring-type joint
SAE	Society of Automotive Engineering
SCC	stress corrosion cracking
S-N	stress-cycle curves
SOHIC	stress-oriented hydrogen induced cracking
SSC	sulfide stress cracking
TOFD	time-of-flight diffraction
UT	ultrasonic testing
UTS	ultimate tensile strength
YS	yield strength (or S_Y)
VME	von Mises equivalent stress
WFMT	wet fluorescent magnetic particle inspection

3.3 Symbols

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

da/dN	fatigue crack growth rate
$(da/dN)_{EAC}$	fatigue crack growth rate developed in service environment
D_i	inside diameter
D_o	outside diameter
Hz	hertz
in.	inch
J_{IC}	fracture toughness measured using the J-integral method in accordance with ASTM E1820
ΔK	stress intensity factor range
K_I	Mode I stress intensity factor
K_{IC}	Mode I critical stress intensity factor
K_{IEAC}	Mode I stress intensity factor measured in service environment
K_{ISCC}	Mode I stress intensity factor measured in stress corrosion cracking environment
K_{th}	threshold stress intensity factor
mA/ft^2	design current density (cathodic protection)
N_f	number of design cycles
R	inside radius
S	design allowable stress
S_{INT}	stress intensity
S_{PL}	allowable limit on local primary membrane and local primary membrane plus bending stress categories [28]
S_Y	yield strength (or YS)
t	wall thickness

4 Addressing Issues Posed in API Technical Report 1PER15K-1

4.1 General

API Technical Report 1PER15K-1: *Protocol for Verification and Validation of HPHT Equipment* (API 1PER15K-1), takes a system level approach to the review of the entire well system, exposed to HPHT conditions. API 1PER15K-1 does not offer analysis tools or design processes for the verification or validation of specific hardware. For that reason, the intent of this technical report is to provide guidance on analysis tools and design processes to address the applications cited in API 1PER15K-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

A broad range of pressure-containing oilfield equipment design is based on the definitions and formulae found in API 6A and API 6X. This is based on ASME *Boiler and Pressure Vessel Code* (*BPVC*) Section VIII, Division 2: 2004 Edition (hereafter ASME Div. 2: 2004). There are limited data available on the use of 30 ksi RWP equipment based on API 6AB (withdrawn) and on 20 ksi RWP equipment based on API 6A in production conditions above 15 ksi; both derived from ASME Div. 2: 2004 design methodology. The design practice from ASME for equipment with design pressure greater than 10 ksi suggests that the equipment designer should consider ASME Section VIII, Division 3. This is the ASME recommendation, but not its requirement. It should be noted that ASME Div. 2 does not specify a limitation on the pressures for which it can be used. For very high pressures (e.g. 20 ksi, 25 ksi, 30 ksi), additional considerations to design and manufacturing practices should be applied to meet the design principles and manufacturing practices to subsea equipment with such pressure ratings.

API documentation continued reference to ASME Div. 2: 2004 where this is not in conformance with ASME's current edition. This was an underlying intent in the development of API 6X where referencing the ASME documents is minimized and API equipment designs will not be subject to unnecessary changes due to revision to the ASME documents.

4.2.1.2 Analytical Methods

With reference to the current ASME *BPVC* Section VIII, Division 2: 2013 Edition (hereafter ASME Div. 2) and ASME *BPVC* Section VIII, Division 3: 2013 Edition (hereafter ASME Div. 3), it should be noted that the design practices and analytical methods (e.g. linear-elastic, elastic-plastic) are similar in principle between these two (2) codes, however, they have different design margins against the plastic collapse load (ASME Div. 2 = 2.4 and ASME Div. 3 = 1.8) and minimum hydrostatic body 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 implements the use of 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. structural discontinuities, notches, sharp corners, etc.). 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 and Thick-Wall Designs

The transition from 15 ksi to higher RWPs tends to change designs from thin-wall to thick-wall pressure vessel designs, where thick-wall is the result of the vessel inside radius to vessel wall thickness ratio equal to or less than "4" ($R/t \leq 4$: ASME Div 2: 2007 and later) or an outside to inside diameter ratio equal to or greater than "1.25" ($Do/Di \geq 1.25$: ASME Div 3: 2010 and later). Two (2) fundamental changes are occurring when transitioning from thin-wall to thick-wall pressure vessel designs.

1) The internal bore yielding (pressure) effect, typically referred to as an "autofrettage" effect (see 3.1.1.).

2) The pressure vessel's possible susceptibility to cyclic loads could theoretically lead 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 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, the API 17TR8 task group contemplated the notion of where do 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 a new design regimen (thick-wall/elastic-plastic analysis). Either way, thick-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, designing products can be more manageable in terms of weight and size, but it comes with the trade-off of more rigorous analysis, validation, and additional quality assurance.

4.2.1.4 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) exact to the "letter" 2) use portions of the code that are applicable to the particular design or 3) 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. They are typically subjected to a variety of extreme external loading conditions and they are not explicitly addressed in ASME *BPVC*. This leads the equipment designer to rely on sound engineering practices and judgment, accompanied by unique validation prototype testing programs.

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

For RWP from 15 ksi, up to and including 20 ksi, there is a transitional zone where both linear-elastic and elastic-plastic design methodologies can be utilized, but with additional considerations. 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 may be applied for this pressure rating range, by using more accurate material model/ properties (true-stress/true-strain). Either way, it relies on higher design margins, hydrostatic body test pressures and sizable material properties to provide adequate design margins to cover complicated or unknown loading conditions. It should be noted that this conservatism may not cover the autofrettage, stress concentrations and mechanical cyclic loads for more complicated geometries. Therefore, design check-gates have been added to alert the equipment designer when simpler design methods or more complicated geometries/ load paths may mask a less stable design result.

For RWP greater than 20 ksi, elastic-plastic design methodology of ASME Div. 3 should be used. It also requires the use of the more accurate material model/properties with additional material quality control requirements.

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

1) For equipment up to and including 15 ksi RWP with HT effects, the traditional or existing linear-elastic analysis in API 6A and API 6X, in conjunction with material properties at operating temperature, is appropriate.

2) For RWP greater than 15 ksi, up to and including 20 ksi, the recommended design practices of ASME Div. 2 through linear-elastic analysis (with additional considerations) or elastic-plastic analysis should be used, to accurately assess the inclusive nature of pressure, temperature and mechanically induced loadings.

3) For RWP greater than 20 ksi, the elastic-plastic design methodology of ASME Div. 3 is recommended, as the internal bore yielding effect becomes more pronounced.

Regardless of the design path taken, these thick-wall designs should culminate with a fatigue screening assessment of its susceptibility to cyclic loads leading to possible fatigue or fast-fracture failures. Cyclic load-screening becomes a part of design regimen, not just a consideration.

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

4.2.1.5 HP Effects on Materials

High pressures can affect produced fluids interactions with materials. For example, the partial pressure of H_2S will go up as the design pressure increases—even if the concentration remains the same. Therefore, a well that can use FF trim at 10,000 psi may require HH trim at 20,000 psi (refer to Table 3 of API 6A or Table 1 of API 17D for material classes).

4.2.2 HT Effects

4.2.2.1 General

The HT effects on materials in HPHT application are understood well qualitatively. They can be well understood quantitatively through an appropriate material testing program and have been documented in API 6MET.

4.2.2.2 HT Effects on Material Properties

The effects of elevated temperature on materials in a corrosive environment are not well documented. 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.

Most available data on material compatibility in severe environments are at room temperature conditions. Severe environment effect should be considered at both temperature extremes. Elevated temperatures typically accelerate localized corrosion and general corrosion rate. Elevated temperature also changes the material's fracture toughness values (i.e. da/dN, K_{IC}, 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 are available at elevated operating temperatures, especially for oilfield equipment.

NOTE API 1PER15K-1 contains tables of commonly used oilfield equipment materials (Table 3, Table 4, and Table 5).

In assessing HT effects on material properties, the lack of available data is a concern. 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, though it is often not the exact material grade. However, 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

Sealing materials against the part geometry is another significant consideration with HT effects. Selection of seal material is a function of it geometry and material properties which should include a 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 molecular bond 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 6J1, ISO 23936-2). Elastomers typically peak at 280 °F (138 °C) and thermoplastics peak at around 400 °F (204 °C) for nominal design life. Higher temperatures are possible but may be with a reduced design/operating life. Metal seals can be a viable solution for higher operating temperatures for extended periods.

Additionally, the less pliable the 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 be easily achievable at lower temperatures, but may require a re-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 the other end of the 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 leading 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 [1,3] and Orr-Sherby-Dorn [2,3]. They observed that highly stressed components at elevated temperature experience a gradual redistribution of the stress in a 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 at the temperatures addressed in this technical report. However, a change of even a few thousandths of an inch may result in loss of preload force in the retaining fasteners or a loss of bearing contact in a seal. For this reason, material testing standards for stress relaxation are addressed in this technical report to help to define material requirements, for seals as well as fasteners (refer to Section 6 and Section 7).

Seals to the environment should be of the highest criticality class and redundancy, where feasible, should be considered for each 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.

4.2.3 Combined HPHT Effects

When combining HP and HT in an application, pressure effects are a function of geometry and material properties, but temperature effects can change material properties and geometries. This results in additional degrees of freedom that then 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 verification and validation tests for every combination.

As indicated above, a change in material selection may change the configuration of a seal pocket assembly, and could result in a need for additional space and hence a larger stack-up in the assembly, even for the same size and rated working pressure. Use of multiple seals or multiple connection points exacerbates the overall assembly size and configuration, and adds to material costs, weight, and assembly complexity.

The industry has been successful in developing HP equipment at lower than HT temperatures, below 350 °F (177 °C). The same has been true for HT equipment at relatively low pressure ratings. However, HPHT permutation may potentially create a unique design, especially 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 HPHT 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 apply appropriately;

   b) constant cold temperature:

      1) massive heat sink,

      2) widens the temperature range,

      3) selective use to augment material properties;

   c) seawater corrosion and cathodic protection effects on material properties.

2) External loads:

   a) cyclic loads imposed by intervention vessels;

   b) cyclic loads imposed by metocean environment;

   c) extreme and survival loads;

   d) increase in in-situ hydrostatic test pressure due to water depth difference between test point and subsea equipment.

3) Flow assurance considerations:

   a) appropriate insulation to minimize heat sinks;

   b) appropriate insulation to achieve temperature rating.

4) Remoteness:

   a) remote monitoring versus restricted service life;

   b) running tool inspection and refurbishment.

Therefore, the equipment functional specifications and basis of design should address and/or include the loading conditions indicated above, as applicable (refer to 5.3).

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 serviceability criteria, and the equipment has adequate protection against failure modes identified for HPHT equipment:

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;

5) fatigue assessment (life-cycle estimation).

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

It is necessary that users of this technical report be aware of regulations from 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 satisfied as a minimum. This technical report provides additional considerations in HPHT equipment designs

In this regard, Figure 1: HPHT Design Flow Chart, illustrates various processes for the design verification, including design validation, for HPHT equipment that requires the equipment designer to:

1) identify the scope of the equipment design rating (e.g. pressure, temperature) for appropriate application of HPHT design flow chart and verification path (refer to 5.2);

2) define the input parameters for design analysis (refer to 5.3);

3) perform the design analysis (refer to 5.4);

4) perform the fatigue assessment/life-cycle estimation, as necessary (refer to 5.5);

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 HPHT Design Flow Chart

5.2.1 General

The application of Figure 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 modes. 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.

The HPHT Design Flow Chart 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 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: API 6A, API 6X, API 17D;

   NOTE API 6A, API 6X, and API 17D reference the design practices of ASME *BPVC* Section VIII, Div. 2, 2004 Edition: Appendix 4.

2) additional requirements for thick-wall equipment analyzed with linear-elastic analysis of ASME Div. 2;

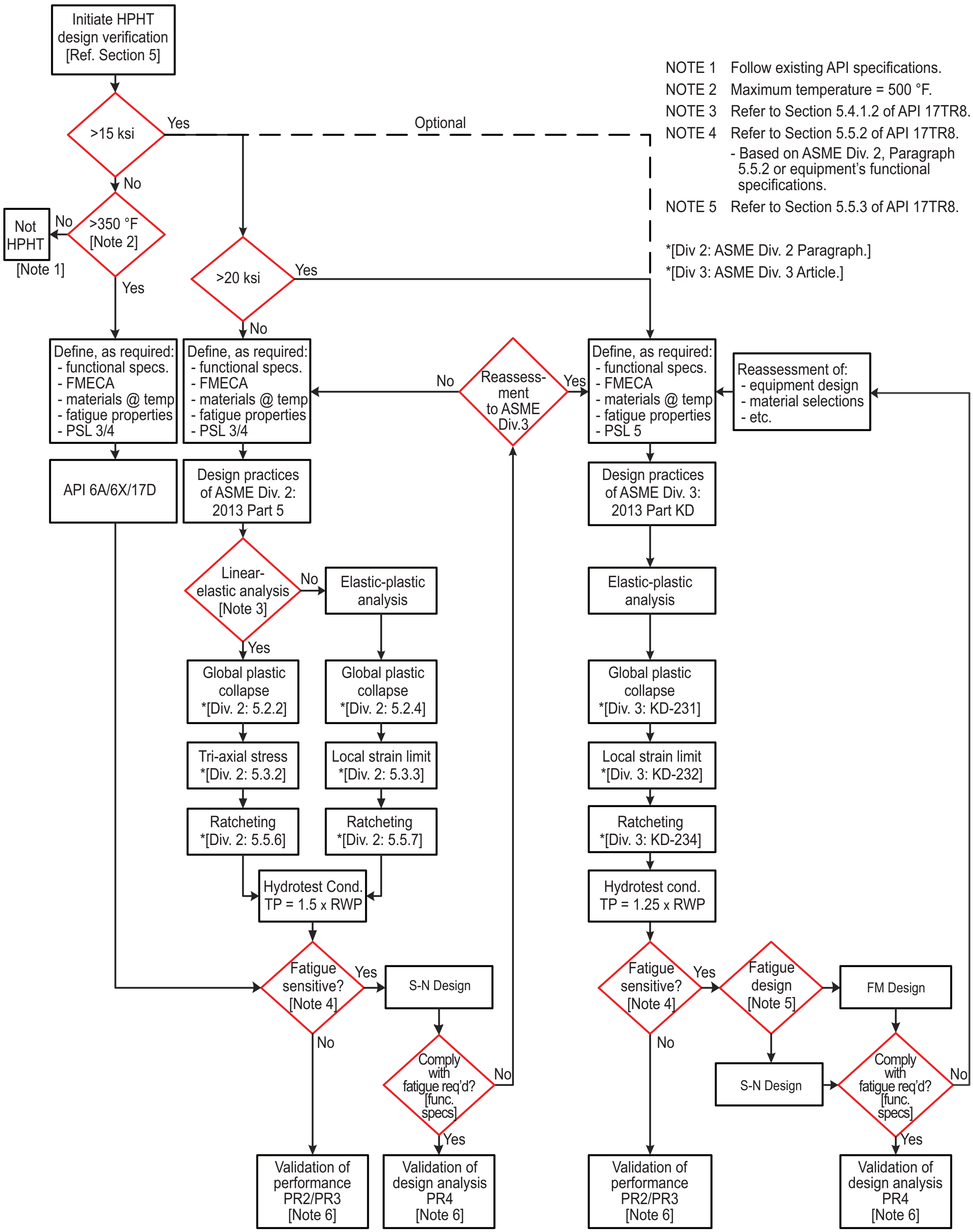

Figure 1—HPHT Design Flow Chart

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 whether a fatigue assessment is necessary to be performed;

5) fatigue assessment (life-cycle estimation).

The analytical method traditionally used in current API product specifications (e.g. API 6A, API 17D) is based upon the design practices of ASME *BPVC* Div. 2, 2004 Edition Appendix 4, applying linear-elastic analysis with design margin defined based on 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 result in higher stresses and strains for pressure-containing components, and therefore, may require the use of thick-wall components. This may require additional assessment and/or advanced methodology for accuracy.

The HPHT Design Flow Chart (Figure 1) permits the use of API 6A and API 6X design verification methodology for equipment with a pressure rating of 15 ksi or lower for use in HT conditions, and within the scope of the applicable governing design standards. Care should be taken that the API 6A/API 6X methodology addresses the effects of the applicable service conditions in a 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 also elect 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) should be defined in such a manner that they are accurately defined in the structural and failure assessments.

Utilizing thick-wall equipment for HPHT application results 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 should be addressed through advanced design methodology.

Therefore, advanced analytical techniques utilizing detailed numerical analysis methods such as finite element analysis (FEA); linear-elastic or elastic-plastic evaluations of ASME Div. 2 or ASME Div. 3 should be utilized in HPHT equipment design, along with more advanced material testing, NDE inspection and acceptance criteria. Application of these techniques provides 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.

Following the design analysis for pressure containment integrity, equipment that may undergo cyclic operations (i.e. pressure, temperature, external loads, etc.) shall be subjected to a fatigue screening further discussion on fatigue assessment is provided in 5.5). Evaluation of the pressure-containing component using the fatigue screening methods of this technical report determines if fatigue analysis is required to calculate its life-cycle characteristics for compliance with the functional specifications. If fatigue analysis is not required based on the screening criteria, this should 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 design), fracture mechanics (FM design), 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 in accordance with API 6A and API 6X or ASME Div. 2, as applicable. This approach has historically been relatively straight-forward for equipment pressure rating of 20 ksi or less, yielding robust designs that can satisfy functional specifications and life-cycle requirements with limited or no need for post-manufacture or “in-service” re-evaluation.

The HPHT Design Flow Chart (Figure 1) introduces the application of linear-elastic analysis in accordance with ASME Div. 2. Although the linear-analysis methodologies of API 6A and API 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 equipment designer shall address the 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 5.4.1.2 to verify protection against local strain failure mode.

Additionally, for pressure rating greater than 15 ksi, the equipment designer is recommended to use the more advanced 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 (Figure 1) offers an alternate direct path to the use of ASME Div. 3 design practices for HPHT equipment, with elastic-plastic analysis and FM design for cyclic fatigue analyses. Additionally, this technical report recommends that ASME Div. 3 be applied for HPHT equipment with pressure ratings greater than 20 ksi.

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, improve certainties 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. it specifies 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 Input Parameters for Design Analysis

5.3.1 Functional Specifications

The design verification process starts with the equipment’s functional specifications. The equipment end-user/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 (Figure 1) 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. H_2S, CO_2, etc.);

3) mechanical/structural loads (external loads);

4) environmental and/or metocean conditions (external load effects);

5) cyclic loading/life-cycle requirements (i.e. pressure cycles, temperature cycles, flow induced loads, external loads, etc.);

6) corrosion, corrosion/erosion requirements;

7) 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.;

8) storage conditions;

9) transportation and installation conditions;

10) applicable industry standards and/or regulatory requirements.

Guidance on developing a functional specification can be found in ISO 13879. API 1PER15K-1 provides additional guidance on elements of the functional specifications. API 1PER15K-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 end-user/operator and/or 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 requirements.

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 1PER15K-1 provides additional guidance on the FMEA process and API 17N provides guidance on the FMECA process. A primary output of the FMECA should be the development of a documented design validation program.

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), specifically for PR3 and PR4, and they should be based on identified failure mode(s) or event(s), as applicable. The definitions, validation testing requirements and considerations for PR3 and PR4 are provided in 8.2.

5.3.3 Material Properties

Applicable material properties (e.g. yield strength, tensile strength, modulus of elasticity), and fatigue properties (e.g. S-N curves, fracture toughness, FCGR) shall be identified and/or generated in accordance with the temperature and environmental parameters specified in the equipment’s functional specifications, and utilized as input parameters for the design analysis of HPHT equipment.

Section 6 provides detailed guidance on the material requirements for HPHT application. General guidance on material selections is provided in Annex B, Material Selection. Guidance on material quality control (QC) is provided in Annex C.

5.3.4 Product Specification Level

The Product Specification Levels (PSL) provide 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 and API 17D product standards (e.g. PSL3 and PSL4), and they are associated with API 6A/API 6X and ASME Div. 2 design practices.

The design flow chart introduces PSL5, where it is applied to ASME Div. 3 design practices. These additional assurance processes are applicable to PSL5, in addition to the requirements of PSL3/PSL4. These additional assurance processes for manufacturing and material quality for PSL5 may include, but not be limited to, the following: material testing and specimen locations:

1) higher Charpy toughness values;

2) fracture toughness (FT) properties;

3) limits on ovality and misalignment;

4) post-hydrostatic body test surface inspection;

5) extent of NDE as QC;

6) NDE capability for flaw detection.

Guidance to the above is provided in ASME Div. 3 Article KM-2 (Mechanical Property Test Requirements for Metals) Fabrication Requirements), Article KF-1 (General Fabrication Requirements), Article KF-2 (Supplemental Welding Fabrication Requirements), Article KE-2 (Requirements for Examination and Repair of Material), Article KE-4 (Final Examination of Vessels).

Specific requirements are to be defined by the equipment manufacturer and end-user/operator.

5.4 Design Analysis

5.4.1 General

For the design analysis of HPHT equipment in accordance with Figure 1, this technical report provides the following guidance to be applied for the design verifications.

5.4.1.1 Design by Analysis

This technical report recommends design-by-analysis based on the use of numerical stress and/or thermal analysis (e.g. FEA) for HPHT equipment. Methodologies associated with design-by-analysis should be 1) linear-elastic, or 2) elastic-plastic analysis. These design verification methodologies are identified in Figure 1 to their respective applications. Section 6.3 advises on the material models and material properties required for these design analysis methodologies.

5.4.1.2 Linear-Elastic Analysis Applied for Thick-Wall Equipment

The traditional application of linear-elastic analysis (in accordance with ASME Div. 2) may result in non-conservative designs from the stress classification procedures (refer to the Hopper diagram of ASME Div. 2, Figure 5.1) to demonstrate structural integrity for thick-wall pressure-containing components ("$R/t \leq 4$" or "$Do/Di \geq 1.25$"), especially around structural discontinuities, or notches. This is due to variations in the stress distribution within the wall thickness.

Therefore, linear-elastic analysis may be used for the design analysis of thick-wall pressure-containing equipment, in addition to the requirements specified in Figure 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 body pressure test load case.

For the ASME Div. 2 design path, the API design allowable stress based on yield strength criteria should be used where $S = 2/3$ x Sy and $S_{PL} = S_Y$. Consideration should be given to minimize the yield strength to ultimate tensile strength ratio.

Mesh sensitivity analysis should be performed to validate the FEA and ensure that the mesh density variations do not affect the stress distribution (within 5 % variance) through the component thickness.

5.4.1.3 Stress Components

The calculated stress components derived from detailed numerical 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 considered a more accurate predictor for the onset of yielding in ductile materials. Load Resistance Factor Design (LRFD).

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 in accordance with ASME Div. 2 or ASME Div. 3, which is considered one of the more accurate analysis methods. This method requires design-by-analysis (e.g. 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).

There are differences in the specified load factors or design margins between ASME Div. 2 (2.4 on plastic collapse load) and ASME Div. 3 (1.8 on plastic collapse load). 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 input and verification by the equipment designers or end-user/operator as described in 5.2.3.

5.4.1.4 Load Descriptions

ASME Div. 2, Table 5.2 and ASME Div. 3, Table KD-230.2 provide descriptions of the loads which are analyzed using these codes. These loads may not directly correspond to the loadings required to be analyzed for API HPHT equipment. The following is the correlation between loads typically experienced in the oil and gas equipment and loads identified in ASME Div. 2 and ASME Div. 3. The defined loads do not identify all loading cases, but provide guidance on load categorization between ASME and API requirements:

P is the internal or external, specified design pressure;

P_T is the hydrostatic body test pressure;

D is the suspension or external loads (i.e. casing loads, external riser or piping loads, installation loads [running], etc.);

L is the fluid dynamic loading (i.e. slugging, water hammer, flow induced vibration, wave and current loading, vortex induced vibration [VIV], etc.);

T is the self-restraining loads, thermal expansions, installation misalignment loads or preloads.

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.

With consideration to the above, the following sections outline the design analysis process in accordance with the HPHT Design Flow Chart (Figure 1) to verify protection against the identified failure modes for HPHT equipment.

5.4.2 Global Plastic Collapse

The design verification for protection against plastic collapse can be accomplished through linear-elastic analysis, where permitted by 5.4.1.2, or elastic-plastic analysis.

1) Linear-Elastic Analysis: API 6A, API 6X, and 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. Section 5.4.1.2 should be considered when linear-elastic methodology is utilized for thick-wall ("$R/t \leq 4$" or "$Do/Di \geq 1.25$") pressure-containing equipment analysis.

   The API design allowable stress based on yield strength criteria should be used where $S = 2/3 \times Sy$ and $S_{PL} = S_Y$. Consideration should be given to minimize the yield strength to ultimate tensile strength ratio.

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 and comply with the global plastic criteria of ASME Div. 2 Paragraph 5.2.2 or ASME Div. 3 Article KD-231.

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 6.3.

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 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. structural discontinuities, notches, etc.) or the triaxial-stress verification within the pressure-containing equipment are defined in ASME Div. 2 Paragraph 5.3.2, where $S = 2/3S_Y$.

2) Elastic-Plastic Analysis: The elastic-plastic analysis can also be used to define a limiting triaxial-strain at peak strain locations (i.e. structural discontinuities, notches, etc.) within the pressure-containing equipment. The local strain analysis should be performed and comply with ASME Div. 2 Paragraph 5.3.3 or ASME Div. 3 Article KD-232.

5.4.4 Ratcheting Effects

Protection against ratcheting, where 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.

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 Paragraph 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 and comply with ASME Div. 2 Paragraph 5.5.7 or ASME Div. 3 Article KD-234.

5.4.5 Global Plastic Collapse under Hydrostatic Body 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 body test pressure specified in Figure 1 and Section 9. The hydrostatic body test condition stress analysis should be performed in accordance with the applicable sections of API 6A, API 17D, ASME Div. 2 or ASME Div. 3.

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.) shall be subjected to a fatigue screening to determine if fatigue assessment is necessary to calculate its life-cycle estimation for compliance with its functional specifications.

There are two (2) methods of evaluating fatigue assessment:

1) S-N design based on alternating stress or strain amplitude;

2) fracture mechanics (FM) design based on material's fatigue crack growth data, da/dN vs. ΔK, 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. Both S-N design and FM design 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 load histograms defined by the end-user, including operating environments design life, and inspection intervals, as applicable. In the absence of specific criteria the manufacturer may assume a representative fatigue cycle histogram, environment design life and inspection interval as the basis for standard product offerings. The equipment end-user/operator should determine if the standard product design fatigue life, operating environment and inspection intervals meet or exceed the expected or actual service conditions. The number of cycles should be adequate to satisfy the end-user/operator defined cycle life and functional specifications. The fatigue cycles should include applicable cyclic loadings for the life of the component, which includes factory testing, installation loadings, and operational loads.

Prior to a fatigue assessment, the global design verification process should identify the most highly stressed regions that are the most critical for fatigue crack initiation and/or fatigue crack propagation/growth. Then a determination should be made to the extent and location(s) where alternating or cyclic loading is taking place. When the FM design is used, the alternating stresses defining the path of crack growth should be based on the maximum principal stress range. The flaw 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 identified.

The traditional S-N fatigue analysis is based on the assumption that the fatigue life of complex structures can be predicted by calculating the highest range of alternating principal stress at any location, then by determining an allowable number of design cycles from laboratory data obtained on strain-cycled, smooth, polished bars. If there are no significant fabrication flaws in the structure, this approach usually produces a conservative result. However, the fatigue life of a smooth, polished bar test specimen is the sum of the number of cycles required to initiate a flaw and the number of cycles to propagate the flaw through the thickness of the specimen. If a metallurgical or fabrication flaw exists at the high stress location in a pressure vessel structure, initiation has already occurred, so the fatigue life of the structure is only the number of cycles required for propagation to failure. This could theoretically give a non-conservative fatigue life, so the more accurate FM design should be selected for cases where a catastrophic loss of containment or fast fracture could result. However, the probability that the S-N design produces a non-conservative result in machined structures in practice is low for the following reasons.

1) The probability that a flaw is located in the region of highest stress is very low.

2) In low-cycle fatigue (<10,000 cycles), the number of cycles required to propagate a flaw to failure in a pressure vessel structure after initiation is almost always greater than the number of cycles required for propagation of a flaw through the laboratory specimen because:

   a) the general stress field at the crack tip in a pressure vessel usually drops off as the crack grows beyond the highly stressed surface;

   b) the maximum permitted flaw size in the pressure vessel structure is usually greater than the thickness of the laboratory fatigue specimen.

3) The S-N fatigue is typically based on a high stress concentration region where the principal stresses decline rapidly through the thickness.

4) The S-N alternating stress is based on the localized high elastic principal surface stress and does not consider shakedown or elastic-plastic stress redistribution.

   NOTE Shakedown areas exhibit a stable hysteresis loop, with no indication of progressive deformation. Further loading and unloading, or applications and removals of the temperature distribution produces only elastic primary and secondary stresses

A fracture mechanics analysis starts with the assumption that a flaw exists at a high cycle stress location. The size of this assumed flaw is the largest flaw deemed acceptable by the non-destructive examination (NDE) criteria that are used in the manufacture of the component(s). It should be noted that it is possible for the fatigue life calculated using the fracture mechanics approach to be greater than that calculated using the S-N approach, particularly in low-cycle fatigue (e.g. a design life less than about 10,000 cycles). However, in high-cycle fatigue (e.g. a design life greater than about 100,000 cycles), the fracture mechanics approach result in a shorter life unless a very large stress intensification factor is used with the S-N approach or a very small initial flaw size can be justified for the FM approach.

5.5.2 Fatigue Screening

The HPHT environment can generate a greater stress field on a component, based on its geometry than standard working pressure equipment. From the inside, bore pressure and temperature may be cyclic, alternating from ambient pressure/temperature conditions to elevated pressure/temperatures while in operation. Similarly, mechanical cyclic loads may be present from metocean conditions, interaction with installation/intervention vessels and equipment, or the pressure-end load effects from internal pressure/temperature changes. With these possible cyclic events, a fatigue screening evaluation is required to determine if the HPHT equipment is fatigue-sensitive, regardless of the design verification path taken as described in 5.2.

The provisions of ASME Div. 2 Paragraph 5.5.2 should be used as the fatigue screening process, based on the material's specified minimum tensile strength, full-range pressure/temperature cycles, and operating pressure/ temperature cycles ranges, as applicable. Successful experience over a sufficient time frame for similar equipment subject to a similar loading histogram can be used as the basis for fatigue screening. Fatigue screening should be evaluated based on a detailed load histogram which should be defined as part of the functional specifications.

5.5.3 Fatigue Design

5.5.3.1 General

If HPHT equipment design does not satisfy the fatigue screening criteria in ASME Div. 2 Paragraph 5.5.2, then a fatigue assessment through the S-N or FM design methods should be performed.

Specific to the ASME Div. 2, the S-N design is provided as the basis for fatigue assessment. However, the equipment designer may elect to use the FM design as an alternative.

Specific to the ASME Div. 3, the guideline for selecting the S-N or FM design is based on the barrier philosophy of API 17A, where:

1) In cases where loss of containment (failure point) occurs in a primary barrier envelope and cannot be contained within a secondary barrier envelope or isolated by a barrier element, the FM design shall be performed for the component fatigue design (e.g. FM evaluation up to and including the secondary barrier envelope, refer to 5.5.3.3).

2) In cases where loss of containment occurs away from the primary barrier envelope, in a secondary barrier envelope where source of the loss can be retained by the primary barrier envelope and barrier element, the S-N design may be performed for the component fatigue design (refer to 5.5.3.2). However, the FM design (refer to 5.5.3.3) may be utilized at the discretions of the equipment designer for the secondary barrier envelope fatigue analysis.

The use of one or more risk assessment techniques such as HAZOP, FMEA/FMECA, QRA, task analysis and/or scenario based risk assessment should be used to determine the location and efficacy of primary and secondary barrier envelopes along with assessment of possible failures and their consequences should a break occur, compromising one of these barrier envelopes (refer to API 17N or other relevant risk management references). The justification for the fatigue assessment approach shall be documented in the system design review, depending on where the component resides within the system and in relation to identified barrier envelopes. The manufacturer's fatigue design documentation shall coincide with the method prescribed for the functional requirements in its intended use, as agreed with the end-user.

5.5.3.2 S-N Design

The S-N design method for fatigue assessment can be based on the methodology prescribed in ASME Div. 2 Paragraph 5.5, ASME Div. 3 Article KD-3, DNV-RP-C203, or BS 7608. The material fatigue properties and/or data should be representative of operating conditions. Section 6.4.2 provides guidance on establishing the S-N fatigue curves with consideration to environmental conditions or DNV-RP-C203 for available S-N curves with consideration to welded specimens/geometry as well as various environmental conditions. The S-N curves used should be based on test specimens from the same class of materials and tested in the same environment conditions (i.e. air, salt water immersion, salt air/salt water spray, high humidity, H_2S, caustic agents, etc.) as expected service conditions. Otherwise results need to be modified by using validated correction reduction factors to account for any degradation in performance or design life.

Fatigue-sensitive locations (i.e. structural discontinuities, notches, etc.) should be identified and fatigue analyses performed on these locations. S-N curves of test specimens with similar representative features should be used, following the procedures in prescribed ASME or DNV code. For welded structures, the structural-stress method for fatigue analysis feature S-N curves of welded specimens/geometries and is found in ASME Div. 2, ASME Div. 3, BS 7608 and DNV-RP-C203.

The result of the fatigue analysis is a calculated number of design cycles, N_f, for each type of operating cycle, and a calculated cumulative effect number of design cycles when more than one type of operating cycle exists. The accumulated fatigue damage should be based on linear cumulative damage, Palmgren-Miner rule, as defined in ASME Div. 2, ASME Div. 3, BS 7608 and DNV-RP-C203.

Where life-cycle estimation represents the number of design cycles based on S-N design, the equipment designer shall ensure that the calculated fatigue life is at a minimum three (3) times the service life for components considered accessible for inspection during its service life. For components that cannot be inspected, the equipment designer shall ensure that the calculated fatigue life is at a minimum ten (10) times the service life. Alternative fatigue life design margins can be applied on a case-by-case basis with appropriate technical justifications in accordance with recognized industry standards and/or validated publication.

The "built-in" design margins on the fatigue curves should be considered.

5.5.3.3 Fracture Mechanics Design

The FM design method for fatigue assessment can be based on ASME Div. 3 Article KD-4, API 579-1/ASME FFS-1 - Part 9 and Annex F, or BS 7910. Section 6.4.3 provides guidance on establishing the fatigue crack growth data associated with FM design. The choice of using either elastic or elastic-plastic FM methodology should be commensurate with the level of sophistication used for the design analyses, global and local, as defined in 5.4.

Where life-cycle estimation represents the number of load cycles to failure based on FM design, the allowable cycles for the intended service life shall be based on the critical crack depth, as specified in 5.5.3.3-3) below.

Additionally, the FM design requires the equipment designer also input, as applicable, the following critical elements.

1) 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_{IEAC}, may be determined by testing or by data that are determined to be as conservative as or more conservative than the actual material properties in the defined environment and loading conditions. Cyclic crack growth material properties for FM design are defined in API 579-1/ASME FFS-1, Annex F or BS 7910. Guidance for fatigue crack growth data is provided in 6.4.3.

2) 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. For complex geometry and assemblies, the ability to identify flaw size and locations should be identified in the application of FM design. The defined initial flaw size is critical in calculating the cyclic fatigue crack growth. The flaw should 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) should 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. Guidance for NDE is provided in 6.6.

3) Critical crack depth: 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. Alternative fatigue life design margins can be applied on a case-by-case basis with appropriate technical justifications in accordance with recognized industry standards and/or validated publication.

4) Multiple flaws: The cyclic fatigue crack growth analysis should define the acceptance criteria for multiple flaws. The cyclic fatigue crack growth analyses should show the flaws are spaced sufficiently for non-interaction over the life of the component or should be based on multiple flaws combined. Additionally, the potential for multiple flaws initiating at several locations should be identified. 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.

5) Load monitoring/“In-Service” inspection: Components and/or equipment which require periodic “in-service” inspection can be evaluated in accordance with ASME Div. 3—Appendix B. Components and/or equipment subjected to “in-service” inspection should have a defined service life adjustment after inspection according to ASME Div. 3—Appendix B. Guidance on load monitoring is provided in Annex A.

   Where “in-service” inspection is not an option available to the equipment end-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.

6) Residual stress effects from hydrostatic body testing or other loading conditions may be applicable when determining the fatigue life, as a means of defining a shakedown condition for alternating stresses.

5.6 Ancillary Systems and Components

5.6.1 HPHT Piping Systems

5.6.1.1 General

Design codes or recommended practices typically used in subsea piping systems downstream of the last subsea tree valve (i.e. manifolds, jumpers, flowlines, etc.) are API 17P, ASME B31.3, ASME B31.4, ASME B31.8, DNV-RP-F112, or API 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;

3) sound engineering judgment on the applicability the selected design code.

Additionally, ASME Div. 2 or ASME Div. 3 may be utilized for HPHT considerations in designing of piping components associated with the piping systems, and therefore, these ASME design practices should be applied consistently with the HPHT applications of this technical report and as defined in 5.2. Further, if the selected design code has a HP section, it should be applied for the HP applications. If the selected design code has a subsea section, then 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. Additionally, misalignment of pipe bores and joints should also comply with the limits of the selected design code or equivalent.

Seam-welded pipes (longitudinal and spiral) should not be used for HPHT applications due to increased difficulty in ensuring consistent quality welded seams.

5.6.1.2 Pipe Wall Thickness

Piping wall thickness calculations should be based on thick-wall formulae of the governing piping design codes for HPHT applications. The required piping wall thickness should be based on the calculated required wall thickness, performed in accordance with the selected piping codes, and should take an additional mill tolerance and corrosion/ erosion allowance into consideration in accordance with the referenced piping specification for nominal wall thickness.

5.6.1.3 Fatigue Assessment/Life-Cycle Estimation

The fatigue assessment of 5.5 should be performed on the HPHT piping systems. If the HPHT piping system is fatigue sensitive, the design fatigue cycles can be calculated by the Palmgren-Miner (S-N) method, API 1111, DNV-RP-D101 or DNV-RP-C203, as applicable. The acceptance criteria for the calculated fatigue-life should meet the requirements of 5.5.

5.6.1.4 Hydrostatic Test Pressure

The piping systems should be pressure tested to the same value as prescribed by the selected piping code or the test pressure defined in Figure 1 and Section 9.

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 5.3.1. Additional guidance on developing a technical specification can be found in ISO 13880. API 1PER15K-1 provides additional guidance on elements of the manufacturer's technical specifications, API 17N and API 17Q provide documentation guidance.

6 Materials for High-Pressure High-Temperature Equipment

6.1 General

6.1.1 Service Conditions

The material selections for HPHT applications should account for the following service conditions, as these affect the material properties.

1) Environmental conditions:

   a) Exposure to produced fluids (oil reservoirs) or condensed fluids (gas reservoirs) and their corresponding corrosivity (i.e. chloride concentration, partial pressure of H_2S (P_{H2S}), partial pressure of CO_2 (P_{CO2}), organic acids, pH, etc.), including seawater that contact the equipment surfaces at the D_i and D_o, as applicable.

   NOTE Partial pressure or fugacity of H_2S and CO_2 are pressure dependent.

   b) The effects of temperature (elevated) on material properties.

2) Cathodic protection (CP).

Guidance on material selection for HPHT equipment with consideration to the service conditions outlined above and guidance for material quality control process is provided in Annex B, and Annex C, respectively.

6.1.2 Standard Material Testing for Environmental Effects

6.1.2.1 General

Material and fatigue properties outlined in Table 1 for qualification testing and correlation by test data for material properties and fatigue properties can be established by the manufacturer with consideration to the standard environmental conditions listed below.

As a benchmark for temperature effects in a proven innocuous environment for the selected material grade, material testing and correlation should be performed using air.

6.1.2.2 Produced/Condensed Fluids

For exposure to produced/condensed fluids in HPHT applications where the actual field specific environmental conditions are not available, material testing and correlation should be performed using one of the following standard fluids, as applicable:

1) NACE TM0177 with Test Solution A or Test Solution B;

2) NACE MR0175/ISO 15156-3, Annex E (nominated sets of test conditions to help determine acceptable limits for the application of CRAs and other alloys).

6.1.2.3 Seawater and Cathodic Protection

For external exposure to seawater and CP, the following should be considered for material testing and correlation to confirm material resistance to HISC (duplex stainless steels) and HAC (CRAs such as Ni-based alloys and other alloys):

1) testing in synthetic seawater produced in accordance to ASTM D1141;

2) CP voltage between –950mV to –1100mV (versus Ag/AgCl) or current density requirements as referenced in NACE SP0176, Table A1 for the specific region.

6.1.2.4 Completion Fluids

For exposure to completion fluids in HPHT applications, appropriate material qualification tests need to be conducted in the specific completion brine contaminated with the field specific production/condensed fluids. Some completion brines that have been used in HPHT applications include:

1) calcium bromide, zinc bromide;

2) potassium chloride, calcium chloride;

3) potassium formate, cesium formate.

6.1.2.5 Drilling Fluids

Drilling fluid considerations should be taken in to account for materials testing and correlation in HPHT applications.

6.1.3 Additional Material Testing for Environmental Effects

Project-specific reservoir, completion, or drilling fluid data should be used to refine the basis for the material qualification testing. Material correlation programs may be defined and agreed upon between the equipment end-user/operator and the manufacturer to identify unique environments or severe service requirements.

6.2 Environmental Effects

6.2.1 General

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

6.2.2 Sour Corrosion—H_2S

H_2S corrosion in the presence of tensile stress may result in a form of hydrogen embrittlement known as sulfide stress cracking (SSC). SSC failure is often catastrophic. It may happen abruptly with no visible warning and may occur at stresses well below the yield strength. Factors contributing to SSC include partial pressure of H_2S, temperature, pH, and presence of CO_2, chlorides, other halides, and stress, including residual stresses in weldments and incidental cold work.

In sour environments, SSC can only be avoided through proper selection of materials. Corrosion-resistant alloy (CRA) cladding of carbon and LAS with filler materials (e.g. ERNiFeCr-1, ERNiCrMo-3), depending on the severity of the environment, can be used as a mitigation barrier with regards to SCC.

NACE MR0175/ISO 15156 serves as the industry guideline for selection of materials for sour service and defines sour service conditions. NACE TM0177 provides testing procedures of metals to determine resistance to SSC and SCC in H_2S environment.

HP wells should be considered as sour with the possibility that the H_2S 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.

6.2.3 Sweet Corrosion—CO_2

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 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 a 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 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. It can be difficult to adequately protect and inspect the complex geometries that can be present in subsea equipment. In such circumstances, predicted corrosion rates should be viewed with caution and the designer should consider CRA or clad CRA designs.

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.2.3) should therefore be used. A PREN greater than 40 is recommended to prevent localized corrosion in seawater if CP is not available.

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 Ni content are more resistant to SCC.

6.2.5 Hydrogen Embrittlement in Seawater with Cathodic Protection

Cathodic protection of metallic materials submerged in seawater may result in formation of atomic hydrogen through direct reduction of the seawater. Atomic hydrogen 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 (i.e. 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. Ni-based alloys are generally superior to steels in resistance to hydrogen embrittlement.

6.3 Material Properties for Design Verification

6.3.1 General

6.3.1.1 Inputs

Table 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 design), as defined in 5.4 and 5.5, respectively. Test specimens shall be in final heat-treated condition, including temper and post weld heat treatment (PWHT), as applicable. In the absence of published data, test environment and temperature should be defined by the project design requirement. For the purpose of material characterization it is recommended that testing be performed at 100 °F increments between 250 °F and 550 °F or 50 °F over the maximum project temperature.

6.3.1.2 Application Guidelines

The following guidelines are applicable to Table 1.

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

2) Additional properties required for design including FT (in seawater plus 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 seawater plus 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 plus two (2) standard deviations (SD).

4) For fatigue crack growth rate (in seawater plus 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 deemed 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.

6.3.2 Material Properties Linear-Elastic Analysis

For linear-elastic analysis, 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,

4) thermal properties, as applicable.

Table 1—Industry Standards for Determination of Material Properties and NDE Required for Design Verification

Parameter	Equipment Category			Reference/Industry Standards		
	Pressure Containing	Pressure Controlling	Closure Bolting and Closure Mechanism	Low-Alloy Steels	Duplex	Ni-Based Alloys
Tensile Properties (Yield, Tensile, Elongation, and Reduction of Area)						
Room Temperature, 75 °F	X	X	X	ASTM A370 ASTM E8		
Elevated Temperature	X	X	X	ASTM E21		
Modulus of Elasticity (Young's Modulus)						
Room Temperature, 75 °F	X	X	X	ASME Section II ASTM E8 ASTM E111		
Elevated Temperature	X	X	X	ASME Section II ASTM E21 ASTM E111		
Hardness*						
Rockwell, Brinell	X	X	X	ASTM E18 ASTM E10		
Vickers, Knoop	X	X	X	ASTM E384		
Toughness						
CTOD (minimum and maximum design temperatures)	X	X		ASTM E1290 ASTM E1820		
K_{IC}/J_{1C} (minimum and maximum design temperatures)	X	X		ASTM E399, ASTM E1820		
CVN* (20 °F below LAST)	X	X	X	ASTM E23		
Fatigue Properties						
Fatigue Crack Growth Rate, *da/dN*	X	X		ASTM E647		
Fatigue Test (S-N)	X	X		ASTM E606 ASTM E2368 ASTM E2714 ASTM E2760		
Nondestructive Examination						
NDE	X	X		ASME Section V **UT:** ASTM A388, ASTM E213, ASTM E273 **MT:** ASTM E709, ASTM E1444 **PT:** ASTM E165, ASTM E1417 **RT:** ASTM E94, ASTM E999, ASTM E1815 **AUT**: DNV-OS-F101, Appendix E		

* QA/QC materials tests included in qualification test program for subsequent correlation that material properties are met through inference that values established for QA/QC material tests during production runs are met.

6.3.3 Material Properties for Elastic-Plastic Analysis

For elastic-plastic analysis, 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 are 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 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 should be considered.

   As an alternate to the true-stress true-strain properties defined in ASME Div. 2 or ASME Div. 3, 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 (38 °C) for tests above 250 °F (121 °C). 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's production phase. Fatigue evaluation of materials for use in oil and gas applications is either based on stress-cycle (S-N design) or fracture mechanics (FM design) by means of FCGR and FT.

6.4.2 S-N Fatigue Curve

The basis of the S-N fatigue curve is to determine a plot of alternating constant-amplitude applied stress range ($\Delta\sigma$) versus cycles to failure or design cycles, N_f, depending on design codes applied. S-N fatigue data in the production environment and in a seawater plus cathodic protection environment should be developed at similar test cyclic frequencies as used to develop fatigue crack growth rates. A test cyclic frequency of 0.2 Hz to 0.3 Hz is recommended in both environments.

Determination of S-N fatigue data in production environments should follow standard NACE MR0175/ISO 15156 procedures for tests environment preparation. Development of S-N data in seawater plus cathodic protection should be performed in simulated seawater prepared in accordance with ASTM D1141. 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 design considers the FCGR determination of a component or pipe material that contains an initial flaw 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 based on component loading direction, preferentially in the L-C orientation (as designated by ASTM 399) unless there is a specific circumferentially oriented radial flaw (C-R) identified by the FM analysis. Fatigue crack growth rate determination procedure should be in accordance with ASTM E647.

Materials used for deep water oil and gas applications are either exposed to production environments (that may contain H_2S) 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 (that may contain H_2S), 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 (EAC) fatigue crack growth, da/dN versus ΔK. Tests should be conducted in accordance with 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 shows that FCGR 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. 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 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 (versus Ag/AgCl) or consideration to the applicable regional design current density (mA/ft^2) as specified in NACE SP0176 Table A1. 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 D1141. 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 in to the FM evaluation should be determined when using either linear-elastic or elastic-plastic fracture mechanics based on the applicable material properties. While constant displacement tests through the double cantilever beam (DCB) method 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 $J_{IC,}$ which can be converted to equivalent parameters in terms of K_{IC}.

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.

2) 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 enables 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 gauge *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 provisions are in addition to the material testing for the qualification process of cracking resistant carbon/LAS and CRAs (e.g. 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. 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 (versus Ag/AgCl) as explained in 6.4.3.3.

FT evaluation using a J-R curve approach should be conducted in the simulated seawater environment (with CP) by following the guidance provided in 6.4.4.2.

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 5.4 and 5.5. The integral cladding or weld metal overlay materials may be considered as part of the pressure-containing structure. Both integrally clad and weld metals used for internal corrosion and erosion-corrosion resistance should be evaluated for physical and mechanical properties defined in 6.3 and the NDE requirements of 6.6, as applicable. Integral cladding and weld metal overlays should meet the requirements of API 6A and 6.5.3. API 6A and API 17D establishes additional volumetric NDE requirements for the use of cladding as part of the pressure-containing structure.

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.

Fabrication welding and welders/welding operations should be qualified in accordance with applicable recognized standards such as ASME Section IX, or equivalents. Hardness requirements and corrosion testing for sour service environments should be in accordance with NACE MR0175/ISO 15156.

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 6.3 for input into the design analyses. The properties for the base metal, integral cladding and/or weld metal should 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 6.4 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. 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.

NDE personnel performing these examinations should have the necessary experience, training, certifications, and qualifications in accordance with 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 equipment manufacturer and end-user's organization.

6.6.2 NDE for Fracture Mechanics—ASME Div. 3

NDE procedure should 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), are defined based on the design verification process. The selected NDE method should 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 detectability 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.

The PoD of a large indication is typically higher than the PoD of a relatively small indication. 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 an HPHT component requires an understanding of the PoD of relevant flaws in that component.

7 Seals and Bolting/Fasteners

7.1 Seals

7.1.1 General

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

The selection of seals should be identified by their pressure and temperature rating. In addition to the operational (static) requirements, there may be dynamic characteristics that are associated with seals for HPHT applications:

1) installation,

2) removal,

3) long duration static followed by dynamic,

4) pure dynamic (speed).

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

7.1.1.1 System Level

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

1) operating pressures (high/low);

2) equipment pressure rating;

3) anticipated operating temperatures (minimum/maximum);

4) cyclic (pressure and temperature sequences);

5) defined operational models that identify:

   a) periods or durations at operational limits (pressure and temperature),

   b) planned schedule of events (i.e. time on production, shut-in, workover, maintenance, etc.),

   c) potential contingency events (i.e. retrieval, unplanned maintenance, abandonment, etc.).

7.1.1.2 HT Applications

In addition to the above, the following considerations should be identified for seals in HT applications.

1) Validation Testing of Seals: Validation testing should 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, and possible cavitation). Flow assurance analysis (CFD) should be conducted to identify the possibility of cavitation around seals. Validate results using appropriate testing, as needed.

2) Rapid Gas Decompression (RGD) Potential: Clear definitions of any potential rapid gas decompression events should be defined for all seals within a selected sub-system or systems, as applicable. Seal system design may be used to compensate for limited material qualification for RGD resistance. RGD validation should be performed on representative seal and gland geometry. Seals or seals systems having elastomeric components which are at risk for RGD damage should be subject to documented RGD evaluation.

3) Thermal Gradients: System thermal analysis can be used to identify the operating temperature limits (maximum and minimum) for seals through 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 may 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 gradient is provided in 8.6.

4) Fluid Compatibility: Fluids used over the life of the well should be identified and understood relative to their effects on seal materials. Expectations for fluid exposure of each seal (type/duration) should be evaluated and documented for the following conditions.

   a) Wellbore/Production fluids—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 documented taking into account design function;

      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 established by the equipment end-user/operator. Any deviation from the plan should consider a compatibility assessment for the injected fluids Potential for corrosion of sealing surfaces from the proposed injected fluids should be assessed.

   c) Control fluids: Thorough consideration to the cleanliness of control fluids should be given when selecting or designing seals. Compatibility of seal materials with control fluids should be assessed and documented in system analysis.

7.1.1.3 Life-Cycle

Life-cycles for seals should consider their shelf-life, operating life and maintenance plan. A shelf-life for non-metallic seals should be established and documented. Storage conditions for seals should be established and documented in accordance with the manufacturer's requirements. Operating life requirements for seals should be defined by the equipment end-user/operator and agreed with the manufacturer.

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 the necessary verification and re-validation requirements to establish adequacy for intended service.

7.1.1.4 Critical vs. Non-Critical Applications

Ramifications of potential seal failure should be considered to determine the impact and consequences of leakage Seals should be classed based on impact criteria and assigned a classification, as agreed by the equipment manufacturer and end-user/operator, which is considered verification and validation procedures.

7.1.1.5 Seal Areas

There can be a number of dynamic seals, where some movement is possible, and static seals in pressure-containing and/or pressure-controlling components. It is important that there is negligible or no damage to the seal faces in these regions. For example, superficial pitting that would not otherwise compromise the integrity of the equipment is unacceptable on the seal faces as it can prevent sealing and possibly tear elastomer seals during movement.

Depending on the particular seal design, careful attention to surface finish may be is required. 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. Good seal surface practices such as lead in chamfers which are burr-free should be followed.

Although these considerations exist in typical subsea application, they may be more critical in HPHT service.

7.1.2 Material Selections

7.1.2.1 General

Seals should 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 reducing material properties. Seal designs subject to tensile loads should be assessed for SCC, SSC, and HIC, etc. In determining stress modes, consideration should be given to combined stresses of thermal gradients, applied pressures, and bending to ensure that an accurate determination has been made of the net stresses in the component.

7.1.2.2 Metallic Seal Materials

Metallic seals should have adequate material properties to fulfill 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 capabilities. Guidance for determination of applicable material properties for metallic seals is provided in Table 1 of 6.3, and appropriate quality control tests are provided in Table C.1 of Annex C.

Additional considerations to metallic seals for HPHT applications are as follows.

1) Corrosion: Corrosion is frequently accelerated by increased temperature; therefore, materials should be inspected in the HT environment with the fluid and material combinations of planned service.

   a) Galvanic: When assessing the seal system for galvanic corrosion, consideration should 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 judgment to evaluate the impact of HPHT to SCC rates.

   c) SSC: Traditionally defined standard service environments due to low percentage concentration of H_2S may actually be sour service due to a high partial pressure H_2S. NACE MR0175/ISO 15156 serves as the industry guideline for selection of materials for sour service and defines sour service conditions.

d) HISC: Cracking due to a combination of load and hydrogen embrittlement (HE) caused by ingress of hydrogen formed at the steel surface due to the cathodic polarization.

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

2) Differential Thermal Expansion: Current designs that are used for lower normal temperature ranges should be reviewed to take into account differential thermal expansion due to HPHT. HPHT environments can create greater deflections; therefore, current designs should be re-evaluated for the greater ranges. Analysis needs to be conducted over the intended temperature range to ensure that seal loading is maintained.

3) Galling: Galling may result from a small relative movement due to alternating bending, thermal expansion, and thermal contraction caused by temperature cycles, ballooning/contraction, incompatible material selection and Poisson's effect as a result of pressure cycles. Material selection should consider options to minimize galling potential.

7.1.2.3 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 6J1 should be conducted.

2) Differential thermal expansion: Thermal expansion due to the high temperatures, component size changes, movement, extrusion gaps, etc., is of greater magnitude for HT services, and therefore, should 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). Additional guidance for consideration to stress relaxation is provided in ASTM D6147, ISO 3384-1 or ISO 6914.

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).

Table 2 identifies industry standards applicable for the determination of plastic properties.

Table 3 identifies industry standards applicable for the determination of rubber properties.

7.1.3 Design Considerations

Full analysis is required to determine the component geometry through the temperature and pressure range including extreme limits to ensure that 1) key design parameters meet manufacturer's requirements and 2) 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 temperature;

2) representative validation;

Table 2—Industry Standards for Determination of Plastic Properties

Parameter	Reference/Source	
	ASTM	ISO
Tensile Property — Tensile and Elongation @ Break — Yield Stress and Elongation	ASTM D638	ISO 527
Hardness	ASTM D2240; ASTM D785	ISO 868
Compression	ASTM D695	ISO 604
Creep	ASTM D2990	ISO 899
Coefficient of Thermal Expansion (CTE)	ASTM D696; ASTM E831	ISO 11359-2
Flex	ASTM D790	ISO 178
Impact	ASTM D256	ISO 180
Melt Flow	ASTM D1238	ISO 1133
Softening Point	ASTM D648; ASTM D1525	ISO 306; ISO 75-2
Specific Gravity	ASTM D792	ISO 1183
H_2O Absorption	ASTM D570	ISO 62
H_2S Gas Effects	NACE TM0187	—

Table 3—Industry Standards for Determination of Rubber Properties

Parameter	Reference/Source	
	ASTM	ISO
Tensile Property — Tensile and Elongation @ Break — Modulus	ASTM D412	ISO 37
Hardness	ASTM D2240; ASTM D1415	ISO 48; ISO 7619-1
Compression Set	ASTM D395	ISO 815-1
Fluid Aging	ASTM D471	ISO 1817
Tear Strength	ASTM D624	ISO 34-1
Temp of Retraction	ASTM D1329	ISO 2921
Specific Gravity	ASTM D792	ISO 2781
Glass Transition Temperature (T_g)	ASTM D5992; ASTM D4065; ASTM D4092	ISO 4664

3) metallic or non-metallic seals;

4) application damage consideration (i.e. deformation of hardware bodies, uncontrolled extrusion gaps, erosion of seal surfaces, etc.);

5) material properties including mechanical and corrosion resistance;

6) material compatibility to avoid corrosion and galling;

7) failure mechanisms (i.e. extrusion, wear, RGD, heat aging, chemical attack, etc.);

8) coatings;

9) consistency of critical properties (batch tolerance);

10) design life determination;

11) volume fill;

12) multiple component seal system considerations.

7.2 Bolting and Fasteners

7.2.1 General

Bolting in HPHT service requires a consideration of stress relaxation, creep and the potential for accelerated corrosion mechanisms. For these reasons, attention should be given to material selection and design stresses.

7.2.1.1 Bolting

7.2.1.1.1 Low-Alloy

For HPHT application, low-alloy steel bolting should be selected in accordance with the quality requirements of BSL-3 of API 20E, and 7.2.3.5.

7.2.1.1.2 CRA

Pending publication of API 20F on Corrosion-Resistance Alloy (CRA) Bolting, addresses the requirements for CRA bolting in HPHT service.

7.2.1.2 Threaded-End Connections

Threaded-end connections should consider analysis of thread profiles in accordance with Section 5 with respect to the applicable failure modes and fatigue assessment.

7.2.2 Design

7.2.2.1 General

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.

7.2.2.2 Bolting

7.2.2.2.1 Allowable stress

The pressure-containing bolting design stress criteria of API 6A and API 17D should be used to define the stress allowables based on linear-elastic analysis. Bolt preload and maximum allowable stress shall meet the requirements of API 17D, Article 5.1.3.5, Closure bolting and critical bolting. Bolting stresses shall be determined considering loading on the closure, including pressure acting over the seal area, gasket loads and any additional mechanical and thermal loads. Threads for pressure-containing bolting should meet the guidelines of ANSI/ASME B1.1, shear area and length of engagement with the appropriate design margins. ASTM standards for bolting material properties and testing should be applied.

Bolt failure can be due to tensile failure of the bolt or shear out of the threads are defined in ANSI/ASME B1.1 and the Society of Automotive Engineering (SAE) reference document by E.M. Alexander [5]. API 6A and API 17D provide a design allowable for the tensile capacity of the bolt. The nut minimum load capacity should be equal to or greater than the maximum bolt tension capacity.

The bolting stress relaxation should be considered when evaluating both functional capacity of the connection where leakage of the gasket could occur with reduced preload and the effects of increased alternating stress from cyclic loading. Guidance for stress relation is provided in ASTM A193 alloy and stainless steel bolting. Stress relaxation can result in reduction in bolt preload or stress redistribution in a component with complex geometry. Stress relaxation test methods for materials and structures are defined in ASTM E328. Definition of stress relaxation is provided in ASTM DS60.

For standard unified inch screw threads (UN and UNR) the nut dilation can affect the tensile capacity of the bolt and the shear strength capacity of the nut. The nut dilation strength factors for “C1” are defined in the SAE reference document [5]. API 6A and API 17D do not define the shear capacity safety factor for the nut. ASTM A194 provides a proof load capacity of the nut which defines the safety factor for shear allowable. The safety factor for nut shear capacity should be equal to or greater than that of the bolt tensile capacity. The nut and bolt stripping factors of “C2” and “C3” are provided in the SAE reference document [5]. The API 6A and API 17D linear-elastic stress criteria for bolting should be used as input into the pressure vessel elastic or elastic-plastic design verification analysis defined in the applicable section of ASME Div. 2 and ASME Div. 3.

7.2.2.2.2 Cyclic Loading

Pressure-containing bolting shall be evaluated for fatigue based on the defined load histogram provided for the equipment. Fatigue screening processes as defined by 5.5.2 can be applied to determine if the HPHT bolting is fatigue-sensitive or fatigue limited.

If fatigue screening indicates the need, pressure-containing bolting subject to cyclic loading should be evaluated based on alternating stress versus cycles, S-N fatigue analysis in accordance with 5.5.3.2 or ASME Div. 2 Article 5.7.3. Bolting geometry is not subject to the plain strain conditions as defined for heavy wall pressure vessels which can result in brittle fracture. Additionally, bolted connections provide redundancy as part of the protection against failure of the connection which limits the need for failure assessment based on fatigue crack growth and can be considered at the discretion of the equipment designer.

The alternating stress for the bolted connection shall be defined as the maximum local principal stress defined from a load increment minus the preload maximum principal stress for the same location. Each load increment is to be evaluated from the load histogram and cumulative damage. The local principal stress should include the load concentration and geometric stress concentrations normally at the root of the thread.

Application of cyclic thermal loading and external loading can be affected by stress relaxation which should be evaluated for both functional and structural requirements. Loss of preload due to stress relaxation can result in gasket leakage over time. Stress relaxation can also result in higher alternating stresses in bolted connections subjected to external loads and alternating pressures and temperatures, which reduces the bolt fatigue life.

7.2.2.2.3 Design Life/Service Life Acceptance Criteria

The service life for bolted connection is dependent on the defined load histogram. A fatigue life prediction for bolting is to be performed using linear-elastic analysis and S-N or e-N fatigue curves and accumulated fatigue damage, based on linear cumulative damage, Palmgren-Miner rule, as defined in the applicable section of ASME Div. 2, ASME Div. 3 or DNV-RP-C203. The required minimum calculated design fatigue life shall be at least three (3) times the service life for components considered acceptable for inspection. For components that cannot be inspected, the calculated design fatigue life shall be at least ten (10) times the service life. Alternative fatigue life design margins can be applied on a case-by-case basis with appropriate technical justifications in accordance with recognized industry standards and/or validated publication.

7.2.2.2.4 Preload

Bolts which are tension preloaded using torque shall meet the guidelines defined in API 17D. Both maximum and minimum preload according to API 17D should be evaluated for bolted connection analysis.

Bolted connections which have been determined to have stress relaxation should be re-torqued or re-tensioned after FAT testing.

7.2.2.3 Thread-End Connections

7.2.2.3.1 Allowable Stress

The allowable stress for threaded-end connections with a stud or bolt installed into a drilled and tapped hole in an outlet body should be defined in accordance with the applicable design standards (e.g. API 6A, API 17D). Typically, threaded-end connections are made in API components which meet the material requirements of API 6A and API 17D. This can result in the female thread having lower YS and UTS than the bolt external thread.

The male thread allowable stress is defined by API 6A and API 17D. The female connection allowable stress should be based on thread stripping and thread shear analyses. In connections where the body of female thread has a lower YS and UTS than the bolt or the male thread, the connection capacity should be based on the female thread shear allowable limits, as defined in 7.2.2.2.1. The shear-out capacity of the body due to the female thread stripping can be increased by additional engaged thread length or by inserts with equivalent material properties to the bolting.

7.2.2.3.2 Cyclic Loading

Refer to 7.2.2.2.2.

7.2.2.3.3 Design Life/Service Life Acceptance Criteria

Refer to 7.2.2.2.3.

7.2.2.4 Structural Bolting—HT Application

High-temperature applications for bolted connections should include an evaluation for thermal expansion stresses of the connection and stress relaxation at maximum operating temperature. The reduced tensile properties for bolting should be defined for a given material or obtained from ASME Section II, Part D Table 4.

7.2.3 Material Selection for Bolting

7.2.3.1 General

When considering bolting either exposed to production or under insulation for HPHT service, it should be recognized that due to the higher partial pressures encountered, materials should be chosen to meet the sour service requirements of NACE MR0175/ISO 15156, where applicable.

7.2.3.2 Materials

7.2.3.2.1 Low-Alloy

API 20E addresses alloy and carbon steel bolting for use in the petroleum and natural gas industries. This document contains three (3) levels of bolting qualification limits. It is recommended that BSL-3 (the highest level) be chosen for HPHT service for use on pressure-containing/pressure-controlling equipment. Level BSL-3 contains enhanced materials, testing and quality requirements. Examples of acceptable bolting grades for sour service would be ASTM A193, B7M and ASTM A320 Grade L7M.

Table 4 identifies industry standards applicable for the determination of material properties to be employed as input to the design analysis (e.g. structural integrity and fatigue analysis, as applicable), and quality control tests for low-alloy steel bolting and fasteners. Test specimens shall be in final heat-treated condition, including temper and post weld heat treatment (PWHT), as applicable. In the absence of published data, test environment and temperature should be defined by the project design requirement. For the purpose of material characterization it is recommended that testing be performed at 100 °F increments between 250 °F and 550 °F or 50 °F above the maximum project design temperature.

7.2.3.2.2 CRA

The pending API 20F should be the resource for the materials, testing and quality requirements of CRA bolting. The materials requirements for the high strength Ni-based alloys used in API 20F, is based on the material requirements stated in pending specifications API 5CRA and API 6A-718 (which include additional Ni-based grades such as 925, 945, 725, and 625 PLUS). Existing API 6A-718 addresses the material requirements for 718 bolting.

Other bolting materials considered under CRAs for HPHT include precipitation hardening stainless steel GR-660 (refer to ASTM A453). This material has shown good service for fully submerged subsea applications. Care should be taken when using this material in splash zones or intermittent wet/dry conditions due to propensity for chloride deposits potentially leading to subsequent corrosion issues.

Typically the Ni-based alloys mentioned above are not susceptible to creep or stress relaxation phenomena at temperatures below 750 °F (399 °C).

7.2.3.3 Stress Relaxation Testing

Stress relaxation should be performed in accordance with ASTM A193. Procedures for relaxation testing are defined in ASTM E328. Stress relaxation of a bolted connection is a measurement under conditions of constant constraint, constant environment and negligible vibration.

The bolted connection is initially constrained by externally applied forces and the change in the external force necessary to maintain this constraint is determined as a function of time. The stress relaxation results should be used to determine the loss of preload in bolted connections for a given material combination of bolt and nut. Therefore, the stress relaxation test should be representative of the maximum stress level and temperature of the connection for the defined service conditions. ASTM DS60 provides a description of the mechanisms of stress relaxation and application of data.

For PH Ni-based alloys, stress relaxation is not considered to be a significant problem below 750 °F (399 °C). There may be more of an effect of stress relaxation on carbon and low-alloy steels at temperatures less than 750 °F (399 °C). Guidance on these phenomena is provided in ASTM DS60. If this is perceived to be significant for a particular application, further testing may be warranted.

Table 4—Industry Standards for Determination of Low-Alloy Steel Bolting Material Properties and Quality Control Tests

Parameter	Reference/Source	
	Primary	Referenced
Tensile Properties (Yield, Tensile, Elongation, and Reduction of Area)		
Room Temperature, 75 °F	ASTM A370	ASTM E8
Elevated Temperature	ASTM E21	—
Modulus of Elasticity (Young's Modulus)		
Room Temperature, 75 °F	ASTM E8	—
Elevated Temperature	ASTM E21	—
Hardness		
Rockwell, Brinell	ASTM A370	ASTM E18; ASTM E10
Vickers, Knoop	ASTM E384	—
Fracture Toughness		
CVN (20 °F below LAST)	ASTM A370	ASTM E23
CTOD (minimum and maximum design temperatures)	ASTM E1820	—
Metallurgical Structure		
Macrostructure (Macroetch)	ASTM A962	ASTM E381
Microstructure (Cleanliness)	ASTM E45	—
Microstructure (Banding / Orientation of Microstructures)	ASTM E1268	—
Microstructure (Grain size)	ASTM E112	—
Stress-Relaxation		
Low-Alloy Steel	ASTM A193	ASTM E328
NDE		
UT	API 6A PSL-3	—
MT	ASTM A962	ASTM E1444
Fasteners		
Low-Alloy Steel	ASTM A193	ASTM F606

7.2.3.4 Environmental Testing

The environmental testing for bolting materials would be the same as the environmental testing methods for pressure-containing product as outlined in Section 6.

7.2.3.5 Impact Testing

For material used for bolting, it is considered that the absorbed energy values for CVN testing, as stated in API 6A and API 17D may not be adequate and may be improved for HPHT service. The CVN values stated in ASME Div. 3 Table KM-234.2(b) should be used as the acceptance criteria for CVN testing. These CVN values are 30 ft-lbf average, 24 ft-lbf minimum.

The test temperature shall be 0 °F (–18 °C) or the specified MDMT (minimum design material temperature), whichever is less.

7.2.4 Corrosion

7.2.4.1 General

Alloy steel bolting in offshore or marine service is susceptible to corrosion. Bolting may also be exposed to conditions that could result in erosion. High temperature may accelerate the effect of both corrosion and erosion. General guidance on types of corrosion and service conditions are provided in Section 6 and Annex B, respectively.

Corrosion and erosion result in loss of material. Any loss of material from bolting that causes the required dimensions to fall outside of the stated limits (as used in the design verification of Section 5) means that the strength of the bolting, especially threads, has been reduced. The equipment designer should determine the impact of the material reduction or this may necessitate enhanced material selection.

7.2.4.2 Corrosion Rate

The corrosion rate is dependent upon both material and environment. The equipment designer should determine the corrosion rate for the specific application for the bolting. Material selection can then be based on this determination.

7.2.4.3 Corrosion Protection Coating

Selection of coatings should be with thorough consideration of in-process and in-service embrittlement susceptibility, dimensional effects (refer to Section 5), and temperature. Some coatings may contribute to HIC or external hydrogen embrittlement (EHE). Zinc and cadmium plating should not be used as these may promote localized galvanic reaction and hydrogen ion generation. Additional guidance on protective coating is provided in Annex B.

7.2.4.4 Environmental Conditions

The location of bolting should also be considered. For example, corrosion of bolting in the splash zone differs from that of submerged bolting. The presence of cathodic protection as described in Section 6 should also be considered, specifically with respect to the hardness properties for low-alloy steel. The maximum individual hardness for all grades of carbon and low-alloy steel should be 34 HRC. Other hardness values may be used with appropriate technical justification.

Bolting subject to sour service shall meet the requirements of the applicable API specifications and the material requirements of this technical report. Additional guidance for bolting in sour service is provided in B.4.1.

Bolting subject to salt spray may be subject to high corrosion rates. Suitable materials and protective measures are recommended. Guidance for bolting subject to salt spray/seawater is provided in B.4.2.

7.2.5 Quality Control

7.2.5.1 General

For HPHT application, low-alloy steel bolting quality requirements are to be in accordance with BSL-3 of API 20E, to the applicable industry standards for bolting and to the additional requirements stated in this technical report. The requirements of this technical report, API 20E, and any other referenced specifications should be harmonized so as not to be in conflict.

7.2.5.2 BSL-3 of API 20E

Material properties should conform to those required by the applicable ASTM grade, as modified by API 20E BSL-3 for low-alloy steel bolting and to the referenced industry standards for other bolting. This should include tensile properties, impact properties, chemistry and metallurgical characteristics (refer to Section 6 and 7.2.3.5).

Sampling and frequency of testing should be in accordance with the applicable/referenced ASTM Grade, API 20E BSL-3 and applicable specifications or for low-alloy steel bolting and to the reference industry standards for other bolting.

Dimensions are to be in accordance with the applicable drawings and specifications. Inspections are to be performed on 100 % of the parts in accordance with API 20E BSL-3.

The test coupon is to be an actual part, whenever possible. Extraction of the test specimens should be in accordance with the applicable specifications and API 20E BSL-3. The testing method and testing results shall be in accordance with the requirements of the referenced ASTM Grade and API 20E BSL-3 for low-alloy steel bolting and to the referenced industry standards for other bolting.

7.2.5.3 Tolerance Considerations for Coated Bolts

Coatings should be specified by the purchaser. A coating specification is required for coatings specified.

The dimensional effect of coating on a 60° thread pitch diameter is 4 to 6 times the measured thickness of the coating. Therefore, the coating specification is to detail the requirements for fit and dimensional measurement for acceptance following coating.

In addition, the specification should state any dimensional adjustments to accommodate coating. However, dimensional adjustments that do not comply with the applicable ASME thread specifications are not permitted.

8 Design Validation

8.1 General

The design validation process is required to demonstrate that the equipment maintains the mechanical integrity and functionality/operability relative 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. stress or thermal FEA, fatigue analysis, fracture mechanics, etc.) should be validated by measurements and testing. Historical validation processes can remain valid if they can be documented, demonstrated as technically sound, and meet the equipment design requirements and service conditions. Guidance for validation of FEA is provided in ASME V&V 10-2006, *Guide for Verification and Validation in Computational Solid Mechanics*.

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,

— erosion/corrosion, and

— other corrosion mechanism, etc.

4) Scaling per API 6A Annex F is not recommended.

API 1PER15K-1 and API 17N 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

8.2.1 General

The governing API product specifications (e.g. API 6A, API 17D) define the minimum validation requirements. Equipment is to be validated for the intended service application to demonstrate that the design and functional requirements have been met. The HPHT Design Flow Chart (Figure 1) defines the Performance Requirements (PR) validation levels required for equipment design based on fatigue screening.

8.2.2 PR2

The governing API product specifications define the minimum validation requirements. For this technical report, the PR2 validation requirements for API 6A or API 17D equipment would be specified in API 6A, Annex F—PR2 or API 17D—Table 3, respectively.

8.2.3 PR3

The validation testing requirements of PR2, as defined in 8.2.2, are applicable plus the additional performance validation testing as identified by the equipment FMECA. These tests are intended to bridge performance requirements identified that are beyond the validation programs of the equipment's governing product specifications.

Based on the equipment FMECA outputs, a PR3 validation program may include, for example:

1) additional performance validation testing at elevated operating temperature in an operating environment;

2) validation of interaction between mating parts that may have varying thermal properties (e.g. different thermal expansion coefficient that may result in excessive relative movement);

3) additional thermal cycles beyond a governing product specification;

4) validation of the equipment plastic shakedown behavior;

5) modification of the defined validation program that cites endurance cycling tests (such as opening or closing at rated working pressure of valves/chokes/actuators) could be conducted in three (3) groups at defined temperature parameters (e.g. elevated, room, and minimum).

8.2.4 PR4

The validation testing requirements of PR3 are applicable plus the additional procedures associated with validating the design verification process of 5.4 and 5.5 with respect to fatigue sensitive components through one of the following methods:

1) strain-gauging program of a representative test specimen or component, and subsequent comparison analysis of the strain-gauging measurements to the numerical (FEA) results (refer to 8.8);

2) component fatigue testing in accordance with recognized standard, i.e. API 17G, etc.

PR4 is also intended as a flag to the end-user/operator that meaningful cyclic or fatigue loading data (pressure, temperature, metocean, external physical movement/load, etc.) needs to be identified in order to define fatigue design life limits for the equipment's intended application. This may require additional scope or specific validation testing which are to be jointly defined and agreed upon between end-user/operator and manufacturer.

8.3 Additional Design Validation Requirements

As described in 5.3.2, a FMECA should be conducted by the equipment manufacturer with input from the equipment end-user/operator, as applicable or necessary; to identify the failure modes of the equipment under anticipated service conditions. The scope of the identified failure modes should be reviewed as part of the manufacturer's validation program to determine if additional tests are warranted to validate performance or mitigate the probability of failure.

Additional and/or specific validation testing, in addition to those prescribed in 8.2.4, can be further defined and agreed upon between the equipment end-user/operator and the manufacturer to validate failure mode(s) warranted by project-specific operational FMECA that identifies failure modes resulting from a special use, unique environments, or severe service requirements.

8.4 Revalidation of Existing Designs

Changes or modifications to existing designs should be assessed to determine their effects on the component and to reassess the validation program, as necessary. Additional guidance on effects ~~on~~ of 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 meet the required design and service life, after undergoing the validation testing process and as agreed by the end-user/operator.

8.6 Validation Considerations

8.6.1 Validation Program

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

1) material characterizations (metallic and non-metallic) [refer to Section 6];
2) erosion/corrosion testing;
3) multiple samples;
4) instrumentation (i.e. 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 confidence in the results. 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. Guidance on number of samples for the design validation testing can be found in API 17N.

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 demonstrated by analytical methods (i.e. scale model testing, FEA, etc.), the validation testing of individual components or sub-assemblies may be deemed adequate 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, e.g. pressure, temperature (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 Analytical Methods

Where testing is used to validate an analytical method, the placement of measuring devices (e.g. strain-gauging) should be correlated with the locations of loadings and resulting stresses (i.e. general/local membrane, combined, peak, etc.) to ensure that keys areas are properly considered. 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.), if available.

Validation of analytical methods should be documented in accordance with manufacturer's quality management system.

Guidance for validation of FEA is provided in ASME V&V 10-2006, G*uide for Verification and Validation in Computational Solid Mechanics*.

9 Hydrostatic Body Test for High-pressure High-temperature Equipment

9.1 General

Each pressure-containing component should be subjected to a hydrostatic body test pressure which, at every point in the component, is within the range of specified test pressure. Water, water with additives or oil 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 (if specified). Lubrication applied during assembly is acceptable. The pressure and temperature during the hydrostatic body test should be recorded by means of a pressure/temperature chart recorder.

Acoustic emission (AE), if used, should be performed in accordance with procedures specified in ASTM E569 to identify potential flaws and the acceptance criteria should be agreed upon by the equipment manufacturer and end-user/operator. The acoustic emission examination should be conducted throughout the duration of the hydrostatic body "in-plant" test.

The hydrostatic body test pressure should not exceed the specified pressure by more than 5%. Hydrostatic body testing should be conducted at room temperature conditions. Hydrostatic body test procedures, sequencing and hold times should meet the requirements of API 6A and API 17D. The hydrostatic body test pressures are defined in the following 9.2 and 9.3 for HPHT equipment.

When hydrostatic test of an assembly/system is performed, after components of different design paths of this technical report are assembled together, there could be potential for overstressing of parts (internal and/or external) during this hydrostatic testing. These gaps should be identified and documented in a FMECA, input to the verification process, and include in the validation program, as needed to identify these discrepancies.

9.2 Pressure Rating ≤20 ksi

For rated working pressure (RWP) less than or equal to 20 ksi, the hydrostatic body test pressure shall be a minimum of 1.5 times the equipment RWP as marked on the component. However, if the design verification is performed using ASME Div. 3 design practices then a minimum test pressure of 1.25 times the RWP should be considered acceptable (refer to Figure 1).

9.3 Pressure Rating >20 ksi

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

The specified hydrostatic body 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 NACE MR0175/ISO 15156.

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

3) API pressure-containing components constructed of LAS conforming to the requirements of 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 RWP >20 ksi.

4) It is documented that material voids [4], 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 body test pressure should 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 body test pressure should be defined to assure material strain hardening due to plastic deformation do not increase its sensitivity to environmental degradation.

7) It has been demonstrated that hydrostatic body testing at higher pressure has direct correlation and/or adverse effects to the equipment local strain limit damage. Local strains can be a governing factor or predictive indicator to equipment design life.

Annex A
(informative)

Load Monitoring

Where necessary, a 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
(informative)

Material Selection

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

Table B.1 specifies the concentration of H_2S (in ppm) in the gas phase required to satisfy sour condition.

Table B.1—H_2S Concentration in ppm to Equal 0.05 psia Partial Pressure at Standard Rated Working Pressures

Rated Working Pressure	10 ksi	15 ksi	20 ksi	25 ksi	30 ksi
H_2S Concentration (ppm)*	5	3.3	2.5	2	1.7
*These calculations are based on linear gas laws.					

For HPHT equipment design, Table B.1 illustrates that the required H_2S concentration to establish sour service condition (as defined by NACE MR0175/ISO 15156) is below the limit for reliable analysis of H_2S concentration. As a result, the evaluation and design of HPHT pressure-containing equipment should consider the oilfield environment that contact the equipment surfaces as sour.

Sour service condition is defined by the NACE MR0175/ISO 15156 as exposure to oilfield environments that contain H_2S and can cause cracking of materials by mechanisms that include SSC, stress- oriented hydrogen induced cracking (SOHIC) and galvanically induced hydrogen stress cracking (GIHSC).

The 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 prevent SSC threat. The following is an overview of NACE MR0175/ISO 15156 requirements.

1) Selecting metallic materials for sour service should involve, as a minimum one or more of the following:

   a) material selection based on NACE MR0175/ISO 15156 requirements;

   b) laboratory testing specified in, as applicable:

1. NACE MR0175/ISO 15156-2, Annex B: "Qualification of carbon and low-alloy steels for H_2S-service by laboratory testing";

2. NACE MR0175/ISO 15156-3, Annex B: "Qualification of CRA's for H_2S-service by laboratory testing";

3. NACE TM0198 for SSRT screening.

c) Documented field experience using the criteria described in NACE MR0175/ISO 15156.

2) Guidance for material selection for tubing hangers in an HPHT system sour environment is given below:

a) Materials for tubing hangers should be age-hardened Ni-based alloys listed in NACE MR0175/ISO 15656-3;

b) Solid CRA tubing hangers are generally recommended because of cost and manufacturing simplicity.

3) Defining the service environment in terms of aggressive species.

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

5) Documenting quality control procedures of the material.

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

NACE MR0175/ISO 15156 recognizes the fact that water (as a liquid) is required for the cracking mechanisms to occur. Hence, for wells producing only dry gas or dry gas injection wells, resistance of materials to these cracking mechanisms is not required. However, in such cases the presence of water, even if only for short periods, should not be 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 on the H_2S partial pressure and pH.

Pressure-containing HPHT equipment is also exposed to production fluids or completion brines at high temperatures and pressures. Due to the 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 (CRA) that demonstrate adequate resistance to localized (pitting and crevice) corrosion and SCC. Selected materials should have adequate resistance to localized corrosion and SCC caused by chloride ions in produced fluids.

Alloy qualification for localized corrosion resistance of selected materials, if not available, should be performed in accordance with ASTM G48 or ASTM G78 in the intended service environments where these alloys are exposed. The NACE MR0175/ISO 15156 standard also gives guidelines on qualification of CRA for SCC resistance in different chloride concentrations brines, partial pressures of H_2S, 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 resistant to seawater corrosion should be protected by combination of external coatings and CP.

PREN is an indicator of the inherent resistance of a stainless steel alloy to localized (pitting and crevice) corrosion in sea water applications. PREN may be useful in ranking stainless steel materials.

Elevated temperature reduces the resistance of stainless steels to localized corrosion in seawater applications. The optimum resistance is exhibited by stainless steels with PREN greater than 40, Ni-based alloys, and Titanium alloys.

PREN is calculated by:

$$\text{PREN} = W_{\text{Cr}} + 3.3\,(W_{\text{Mo}} + 0.5W_{\text{W}}) + 16W_{\text{N}}$$

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. A well designed and installed CP system normally protects against the following mechanisms.

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 can promote cracking. Industry and service experience has shown that external hydrogen embrittlement can be minimized if:

1) maximum allowable individual hardness of all grades of carbon and low-alloy steel 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 the API definition, pressure-controlling components (i.e. actuators, valve components, etc.) control and regulate the movement of pressurized fluids. For HPHT systems exposed to sour service conditions, materials for major components that are wetted by process fluids should comply with NACE MR0175/ISO 15156.

Guidance for material selection for an HPHT system sour environment are given below.

1) Selecting metallic materials for sour service should involve, as a minimum one or more of the following:

    a) material selection based on NACE MR0175/ISO 15156 requirements;

    b) laboratory testing specified in, as applicable:

        1. NACE MR0175/ISO 15156-2, Annex B: "Qualification of carbon and low-alloy steels for H_2S-service by laboratory testing",

        2. NACE MR0175/ISO 15156-3, Annex B: "Qualification of CRA's for H_2S-service by laboratory testing",

        3. NACE TM0198 for SSRT screening;

    c) documented field experience using the criteria described in NACE MR0175/ISO 15156.

2) Defining the service environment in terms of aggressive species.

3) Documenting quality control procedures of the material.

B.4 Bolting and Fasteners

B.4.1 Sour Service Application

Bolting and fasteners in sour service should comply with NACE MR0175/ISO 15156 if in contact with any concentration of wet H_2S, 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 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 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 hot or cold working);

    c) Class 2 bolts of ASTM A193/A193M are not permitted.

2) High strength steels for internal bolting and springs, bellows, and parts of reciprocating compressors should comply with NACE MR0175/ISO 15156, if in contact with any concentration of wet H_2S.

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 the quality requirements of BSL-3 of 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) CRA and CRM 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).

   CRA/CRM 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 seal system is likely to contain a mixture of metallic materials for packing retainers (i.e. brass, aluminium bronze, steel, etc.). It is important to ensure that elastomer sealing configurations provide equivalent sealing protection to the metallic sealing protection systems. 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) UNS S31600 (316 SS) and UNS N08825 (Alloy 825) with hardness limit of 200 BHN are acceptable.

4) If UNS S31600 and UNS N08825 with hardness limit of 200 BHN are specified, UNS N06625 (Alloy 625) inlay of ring groove should be specified.

5) Depending on the corrosivity of the fluids, wet made joints should have UNS N08926 or UNS N06625 gaskets.

6) Metal to metal seals that may be exposed to seawater without CP should be specified in UNS R0035, UNS R0003, Alloy UNS N06625, or UNS N10276 (Alloy C276).

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

8) For CRA connectors, high strength CRAs that comply with NACE MR0175/ISO 15156 should be specified.

Annex C
(normative)

Material Quality Control

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

	Low-alloy Steels	Duplex Stainless Steels	Ni-Based Alloys
Chemical composition	ASTM A751 ASTM E350 ASTM E1806	ASTM E353	ASTM E1473 ASTM E55
Hardness	ASTM A833, ASTM E10, ASTM E18, ASTM E140, ASTM E384		
Yield strength	ASTM A370, ASTM E8, ASTM E21		
Tensile strength			
% Elongation			
% Reduction in area			
CVN Toughness (20 °F below LAST)	ASTM E23, ASTM E399, ASTM A673		
J_{IC}, K_{IC}, CTOD (minimum and maximum design temperatures)	ASTM E1290, ASTM E1820		
Microstructural examination, grain size	ASTM E112 ASTM E1382	ASTM E112 DNV-RP-F112	ASTM E112 ASTM E1181
Microstructural examination, inclusion rating	ASTM E45	n/a	n/a
Microstructural examination, phase balance	n/a	ASTM E562, ASTM E1245	n/a
Microstructural examination, deleterious phases	ASTM E45, ASTM E768, ASTM E1122, ASTM E1245	ASTM A923	n/a
NDE, ET	ASME Sec V, ASTM E309, ASTM E376, ASTM E426, ASTM E566, ASTM E571, ASTM E703		
NDE, MT	ASME Sec V ASTM A275, ASTM E709, ASTM E1444	n/a	n/a
NDE, PT	ASME Sec V, ASTM E165, ASTM E1417		
NDE, RT	ASME Sec V, ASTM E94, ASTM E999, ASTM E1815		
NDE, UT	ASME Sec V, ASTM A388, ASTM E 213, ASTM E273, ASTM E2375		
Corrosion testing	n/a	ASTM G48	n/a
Positive material identification	API RP 578		

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 is 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 should 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 is based on heat analysis, check analysis or both;

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

C.5 Mechanical Properties

Mechanical properties of production-lots of components should be verified to meet the properties assumed during design and verification. 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 EAC.

   Tension tests at the anticipated maximum operating temperature may be required for applications with maximum temperature in excess of 250 °F (121 °C). The yield and tensile strength requirements for elevated-temperature tension tests should align with the assumptions for de-rating of strength at elevated temperatures (refer to API 6MET).

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 or below the lowest anticipated service temperature (LAST) or minimum design metal temperature (MDMT) The test temperature can be reduced a specified amount below LAST or MDMT to account for variation 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 CRM, 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 the following.

   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 (3) 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 (3) may also be specified.

      CVN data are 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 analysis. 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_{IC}, K_{IC} or CTOD: FT tests such as J_{IC}, K_{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 well controlled. 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 in accordance with 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 well controlled.

2) CRM: Evaluations of the microstructure of duplex stainless steels and precipitation-hardened Ni-based 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 in accordance with 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 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 (3) 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 effective method to assess deleterious third phases in duplex stainless steels.

4) Nickel-Based Alloys

a) Grain Size: Determining the average grain size of Ni-based 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 Ni-based alloys. ASTM E1181 identifies the following three (3) conditions of duplex grain sizes:

   1. cross-section condition,

   2. necklace condition,

   3. banding condition.

   As a comment on 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 Ni-based 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 performing these examinations should have the necessary experience, training, certifications, and qualifications. NDE shall be performed in accordance with written procedures that include acceptance criteria. 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 in accordance with 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 accessible surface areas, and should be performed prior to and after final heat treatment. 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. 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 austenitic CRA surfaces, and other Ni-based alloys should use the fluorescent penetrant process. 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 (refer to ASTM E1417) should be conducted prior to the examination of production components, and the test should be able to detect the five (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.

A: 0.015 in. to 0.031 in. (0.38 mm to 0.79 mm)

B: 0.046 in. to 0.062 in. (1.17 mm to 1.57 mm)

C: 0.075 in. to 0.093 in. (1.91 mm to 2.36 mm)

D: 0.125 in. to 0.171 in. (3.18 mm to 4.34 mm)

E: 0.180 in. to 0.250 in. (4.57 mm to 6.35 mm)

2) Volumetric NDE: Volumetric NDE is primarily used to examine the internal integrity of materials or components. Volumetric examinations may also aid in the detection of surface connected discontinuities.

   a) Radiographic Testing: Radiographic testing (RT) can be practical for volumetric NDE of subsea components with relatively thin wall thickness. For HPHT applications, radiography may not be the recommended NDE technique for volumetric examinations. Radiographic contrast and sensitivity reduced as part thickness increases. As a result, 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 should 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. This is due to radiography being able to provide only qualitative two-dimensional flaw data. RT images of discontinuities can allow an estimation of length and width of flaws but do not provide useful information with regards to flaw depth or cross sectional area.

   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 (refer to 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 is not a substitute for conventional chemical analysis discussed in Annex C.4.

NOTE There are two basic types of PMI instruments: Portable X-ray Fluorescence and Portable Optical Emission Spectrometry. Results from these two 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.

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.

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[146] ISO 6892-1, *Metallic materials—Tensile testing—Part 1: Method of test at room temperature*

[147] ISO 6892-2, *Metallic materials—Tensile testing—Part 2: Method of test at elevated temperature*

[148] ISO 6914, *Rubber, vulcanized or thermoplastic—Determination of ageing characteristics my measurement of stress relaxation in tension*

[149] ISO 7619-1, *Rubber, vulcanized or thermoplastic—Determination of indentation hardness—Part 1: Durometer method (Shore hardness)*

[150] ISO 11359-2, *Plastics—Thermomechanical Analysis (TMA)—Part 2: Determination of Coefficient of Linear Thermal Expansion and Glass Transition Temperature*

[151] ISO 13879, *Petroleum and Natural Gas Industries—Content and Drafting of a Functional Specification*

[152] ISO 13880, *Petroleum and Natural Gas Industries—Content and Drafting of a Technical Specification*

[153] ISO 23936-2, *Petroleum, petrochemical and natural gas industries—Non-metallic materials in contact with media related to oil and gas production—Part 2: Elastomers*

[154] NACE SP0176, *Corrosion Control of Submerged Areas of Permanently Installed Steel Offshore Structures Associated with Petroleum Production*

[155] NACE TM0177, *Laboratory Testing of Metals for Resistance to Sulfide Stress Cracking and Stress Corrosion Cracking in H_2S Environments*

[156] NACE TM0187, *Evaluating Elastomeric Materials in Sour Gas Environments*

[157] NACE TM0198, *Slow Strain Rate Test Method for Screening Corrosion-Resistant Alloys for Stress Corrosion Cracking in Sour Oilfield Service*

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