Recommended Practice for Dynamic Risers for Floating Production Systems

API Recommended Practice 2RD

Third Edition, XXXXXXXX, 202X

Introduction

The first edition of API RP 2RD, *Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tensioned-Leg Platforms (TLPs)*, was issued in June 1998 and was based on a working stress design methodology. At the time, the first steel catenary risers had only been in the water for a few years. Hence the first edition was focused primarily on top-tensioned risers and did not consider the interfaces with pipeline design codes for steel catenary risers.

The second edition, issued in September 2013, was renamed API STD 2RD, *Dynamic Risers for Floating Production Systems*, reflecting the broader application to all floating systems. The second edition was a complete re-write of the document, replacing working stress design with limit state design methods, with the intention of being issued as an ISO standard, and subsequently adopted by API. It was also generalized for compatibility with pipeline design codes and other limit state design standards. It included four alternative methods for combined stress design, including one method based on DNV-ST-F201 and one method considering large strain. In the end, the connection with ISO was severed and it was issued by API as API STD 2RD. Technically, it became an API Standard rather than an API Recommended Practice, which was an API administrative change that had no material effect on the content.

Since the issuing of the second edition in 2013, a number of shortcomings have been identified, including a lack of guidance on the use of the large strain method 4, and a lack of compatibility with the first edition working stress design method for re-assessment of existing risers. In addition, important feedback was provided from the development of API RP 2RIM *Integrity Management of Risers from Floating Production Systems*, as well as industry experience with the re-assessment of risers. The second edition also lacked a commentary annex, or the extensive embedded informative text from the first edition.

This third edition makes several changes from the second edition, including –

- Incorporating an optional working stress design method compatible with the first edition;
- restructuring the design criteria (Section 5), combining common elements of the working stress (first edition) and limit state (second edition) design methods, and including clearer guidance on the use of the different design methods;
- removing Method 3 (based on DNV-ST-F201) from Section 5 to maintain compatibility with the underlying API pipeline design codes;
- removing Method 4 from Section 5 and incorporating the provisions of Method 4 into other sections;
- incorporating Safety Class into the design criteria;
- clarifying fatigue design requirements (Section 5.6);
- maintaining compatibility with API RP 1111 for pipeline risers;
- adding an extensive Informative Commentary (Annex A) to provide guidance and supplemental reference material for specific sections of the Normative;
- adding Informative Annex B to address general riser design topics applicable to more than one section of the Normative;
- updating examples (Annex C) illustrating the differences between design methods;
- referring to existing standards by reference, replacing some explicit material and welding requirements (Section 7).
- reverting to a Recommended Practice (RP) API document type (i.e., same as first edition), consistent with other similar API offshore design standards (refer to Annex A for further explanation).

Dynamic Risers for Floating Production Systems

1 Scope

This Recommended Practice addresses dynamic riser systems that are part of a floating production system (FPS). A dynamic riser is a subsystem in a floating production system. For guidelines for design, construction, installation, operation, and maintenance of floating production systems, refer to API RP 2FPS and API RP 2T.

The provisions of this standard do not apply to the riser systems of mobile offshore drilling units (MODUs). For MODU riser design, refer to API RP 16Q [S02].

There is significant interaction among the subsystems in a floating production system. Hull motions affect risers and moorings, and conversely, risers and moorings affect hull motions. Global behavior of the system provides input to assessment of subsystems. Assessment of a subsystem provides feedback (e.g., loads, motions) for assessment of the hull and other subsystems.

Determination of the boundaries of a riser system and management of the interactions with other subsystems is the responsibility of the operator.

A riser system is an assembly of components, including pipe and connectors. A riser system can include a riser tensioning system, buoyancy modules, VIV suppression devices, corrosion protection, thermal insulation, etc. Pipe components can be steel, titanium, or unbonded flexible pipe. Composite materials may be considered but they are not directly addressed in this Recommended Practice. Design considerations for unbonded flexible pipe are included primarily by reference to API RP 17B and API Spec 17J. Steel and titanium pipe are referred to as rigid pipe and unbonded flexible pipe is referred to as flexible pipe.

All or part of several existing codes, standards, specifications, and recommended practices are included by reference.

Design loads and conditions are described in Section 4. Structural design criteria for rigid pipe are in Section 5. Structural capacity criteria for steel pipe are also in Section 5. Additional requirements for riser components are in Section 6. Material requirements are in Section 7. Fabrication and installation requirements are in Section 8. Integrity Management is addressed in Section 9 and by reference, in API RP 2RIM.

2 Normative References

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

API Std 1104	*Welding of Pipelines and Related Facilities*
API RP 1111	*Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)*
API RP 2RIM	*Integrity Management of Risers from Floating Production Facilities*
API Spec 5CT	*Casing and Tubing*
API Spec 5L	*Line Pipe*
API RP 5L1	*Recommended Practice for Railroad Transportation of Line Pipe*
API Spec 5LC	*CRA Line Pipe*
API RP 5LW	*Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*
API Spec 17D	*Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment*
API Standard 17G	*Design and Manufacture of Subsea Well Intervention Equipment*
API Spec Q1	*Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry*
ASME B16.49	*Factory-Made, Wrought Steel, Buttwelding Induction Bends for Transportation and Distribution Systems*
ASME BPVC, Section IX	*Welding, Brazing, and Fusing Qualifications*
ASTM A240	*Standard Specification for Heat-Resisting Chromium and Chromium-Nickel Stainless Steel Plate, Sheet, and Strip for Pressure Vessels*
ASTM B381	*ASTM B381 - Standard Specification for Titanium and Titanium Alloy Forgings*
ASTM B446	*Standard Specification for Nickel-Chromium-Molybdenum-Columbium Alloy (UNS N06625), Nickel-Chromium-Molybdenum-Silicon Alloy (UNS N06219), and Nickel-Chromium-Molybdenum-Tungsten Alloy (UNS N06650) Rod and Bar*
ASTM E384	*Standard Test Method for Microindentation Hardness of Materials*
ASTM F467	*Standard Specification for Nonferrous Nuts for General Use*
AWS A5.14/A5.14M	*Specification for Nickel and Nickel- Alloy Bare Welding Electrodes and Rods*
BS 7608	*Guide to fatigue design and assessment of steel products*

DNV-RP-C203	*Fatigue design of offshore steel structures*
DNV-ST-F101	*Submarine pipeline systems*
DNV-RP-F108	*Assessment of flaws in pipeline and riser girth welds*
ISO 9934 (all parts)	*Non-destructive Testing - Magnetic Particle Testing*
ISO 12135	*Metallic materials — Unified method of test for the determination of quasistatic fracture toughness*
ISO 15589-2	*Petroleum, petrochemical and natural gas industries - Cathodic protection of pipeline transportation systems - Part 2: Offshore pipelines*
ISO 15590-1	*Petroleum and natural gas industries - Induction bends, fittings and flanges for pipeline transportation systems - Part 1: Induction bends*
NACE MR0175/ISO 15156 (all parts)	*Petroleum and natural gas industries - Materials for use in H2S-containing environments in oil and gas production*

API RP 2FPS	*Planning, Designing, and Constructing Floating Production Systems*	4.3.1
API Spec 2SF	*Manufacture of Structural Steel Forgings for Primary Offshore Applications*	7.2.2
API RP 2SK	*Design and Analysis of Stationkeeping Systems for Floating Structures*	4.3.1
API RP 2T	*Planning, Designing and Constructing Tension Leg Platforms*	4.3.1
API RP 5C5	*Procedures for Testing Casing and Tubing Connections*	6.1 7.2.2
API Spec 6A	*Specification for Wellhead and Tree Equipment*	7.10.1
API RP 17B	*Recommended Practice for Flexible Pipe*	7.2.2
API Spec 17J	*Specification for Unbonded Flexible Pipe*	7.2.2
API Spec 17K	*Specification for Unbonded Flexible Pipe*	7.2.2
API Spec 17L1	*Specification for Ancillary Equipment for Flexible Pipes and Subsea Umbilicals*	6.1 7.2.2
API Spec 17L2	*Recommended Practice for Flexible Pipe Ancillary Equipment*	6.1 7.2.2
API Spec 16F	*Specification for Marine Drilling Riser Equipment*	6.1.1
API Spec 20B	*Open Die Shaped Forgings for Use in the Petroleum and Natural Gas Industry*	7.2.2
API Spec 20C	*Closed Die Forgings for Use in the Petroleum and Natural Gas Industry*	7.2.2

API Spec 20E	*Alloy and Carbon Steel Bolting for Use in the Petroleum and Natural Gas Industries*	7.2.2
API Spec 20F	*Corrosion-Resistant Bolting for Use in the Petroleum and Natural Gas Industries*	7.2.2
ASTM E1820	*Standard Test Method for Measurement of Fracture Toughness*	7.8.2
ASTM E1823	*Standard Terminology Relating to Fatigue and Fracture Testing*	7.8.2
ASTM G48	*Standard Test Methods for Pitting and Crevice Corrosion Resistance of Stainless Steels and Related Alloys by Use of Ferric Chloride Solution*	7.11.11
BS 7910	*Guide to methods for assessing the acceptability of flaws in metallic structures*	5.6.5
DNV-RP-0034	*Steel forgings for subsea applications – Technical requirements*	7.2.2
DNV-ST-F119	*Thermoplastic composite pipes*	7.2.2

3 Terms, Definitions, Symbols and Abbreviated Terms

3.1 Terms and Definitions

For the purposes of this document, the following terms, definitions, symbols, and abbreviations apply.

3.1.1
agreement
agreement between manufacturer and purchaser at the time of enquiry and order, unless otherwise indicated

3.1.2
attachment weld
fillet or full penetration weld used for attachment of components to pipe or coupling

3.1.3
blow-out preventer
BOP
large, specialized valve used to seal, control, and monitor an oil and gas well during drilling and completion operations

3.1.4
BOP stack
assembly of well control equipment including BOPs, spools, valves, hydraulic connectors, and nipples that connects to the subsea wellhead or to the surface wellhead on top of a high-pressure drilling riser

3.1.5
buoyancy modules
structures of density less than that of sea water, usually foamed polymers, strapped or clamped to the exterior of a riser to reduce the submerged weight of the riser or to change the geometric configuration of the riser.

3.1.6
component
part of a riser system

NOTE Includes structural components such as pipes, connectors, stress joints, tension joints, landing blocks, slick joints, tubing hanger orientation joints, adapter joints, etc.

3.1.7
connector
mechanical device used to connect adjacent components in the riser system to create a structural joint resisting applied loads and preventing leakage

EXAMPLE (a) threaded types including (i) one male fitting (pin) and one female fitting (box), or (ii) two pins, a coupling and seal ring(s), (b) flanged types including two flanges, bolts and a gasket/seal ring, (c) clamped hub types including hubs, clamps, bolts and seal ring(s), (d) dog type connectors.

3.1.8
corrosion allowance
erosion allowance
wear allowance
amount of wall thickness added to the pipe or component to allow for anticipated uniform material loss due to internal corrosion, erosion, or wear

3.1.9
crack tip opening displacement
CTOD
A material test in which the distance between the opposing faces of the crack tip is measured after load cycling, used as a measure of the material resistance to crack propagation (fracture toughness)

3.1.10
design basis
set of project-specific design data, specifications, and functional requirements provided by the operator

3.1.11
design factor
allowable utilization factor reflecting the ratio of the calculated value to the allowable value, equal to one or less

3.1.12
design life
time period, starting at installation, for which a riser is to be used for its intended purpose with anticipated maintenance, but without substantial repair or replacement being necessary

3.1.13
design load
combination of load effects

3.1.14
design pressure
maximum sustained difference between internal pressure and external pressure during normal operations, referred to a specified elevation

3.1.15
displacement controlled response
a riser response scenario in which the relevant loads acting on the section under evaluation will be relieved by global deformations of that section (i.e., loads are dependent on deformation, such as temperature-induced loads) or the displacement is controlled by geometric constraints (e.g., pipe on a reel)

3.1.16
drilling riser
system used with a FPS for guiding the drill string and circulating fluids between the drilling vessel and the seafloor

3.1.17
effective tension
axial force in the pipe wall less the internal pressure multiplied by the inside area of the pipe plus the external pressure multiplied by the outside area of the pipe

NOTE Effective tension accounts for the effects of hydrostatic pressure in structural analysis of pipe.

3.1.18
emergency shut-down
ESD
shut down of the facility under emergency conditions

NOTE An emergency shut down is unexpected but could turn into an extended shut-in (see separate definition). The design pressure of the riser equipment up to and including the ESD valve should consider the effect of shut-in pressure which is higher than the normal operating pressure.

3.1.19
engineering criticality assessment
ECA
a fitness-for-service assessment to provide a rational basis for the safe and economic operation of critical structures

NOTE Fracture mechanics principles are used to evaluate whether or not a given flaw is safe from brittle fracture, fatigue, creep or plastic collapse under specified loading conditions.

3.1.20
extended shut-in
closure of isolation valve(s) at top of riser for a period of time that can last for days, during which the internal pressure in a production riser can increase above the normal operating pressure

NOTE: For production flowlines, the riser may be displaced to dead oil to limit the risk of formation of hydrates. Shut in conditions for each riser should be defined in the operating plan.

3.1.21
failure
event causing an undesirable condition, e.g., loss of component or system function, or deterioration of functional capability to such an extent that the safety of the unit, personnel or environment is significantly reduced

NOTE: Examples are structural failure (excessive yielding, buckling, rupture, leakage) or operational limitations (excessive riser tensioner stroke).

3.1.22
flexible joint
laminated metal and elastomer assembly, having a central through-passage equal to or greater in diameter than the interfacing pipe or tubing bore, that is positioned in the riser string to reduce the local bending stresses

3.1.23
floating production system
FPS
host platform
vessel
a permanently moored floating platform that serves as the host for the risers under consideration

3.1.24
fracture mechanics assessment
analysis where critical defect sizes under design loads are identified to determine the crack growth life before leak or fracture is expected to occur

3.1.25
galling
cold welding of contacting material surfaces followed by tearing of the materials during further sliding/rotation

NOTE Galling results from the sliding of metallic surfaces that are under high bearing forces. Galling can generally be attributed to inadequate lubrication between the surfaces. The purpose of the lubrication medium is to minimize the metal-to-metal contact and allow efficient sliding of the surfaces. Other ways to prevent galling are to reduce the bearing forces or reduce the sliding distance.

3.1.26
global analysis
analysis of the complete riser string from subsea termination to the interface where loads are transferred to the FPS

NOTE Bending moments and effective tension distributions along the riser string due to functional loads, vessel motions and environmental loads are determined by global analysis.

3.1.27
heat-affected zone
region around a weld or cut that has been affected by welding or high temperature cutting, leading to changes in material properties

3.1.28
hybrid riser
riser with a free-standing vertical section connected to the seabed, supported by a subsurface buoyancy tank at the top and connected to the FPS by flexible pipe jumpers

3.1.29
incidental pressure
temporary pressure increase due to transient conditions

EXAMPLE Incidental pressure occurs in situations where the pressure increases temporarily due to surge, well-kill (bull heading), failure of a pressure protection system, or other incidental conditions. Incidental pressure can exceed design pressure temporarily.

3.1.30
kick
influx of reservoir fluid into the wellbore during drilling or workover that results in shutting in the well and increased pressure below the shut-in device (usually a BOP)

3.1.31
limit-state design
a design approach that considers strain limits and stress limit as opposed to stress limits only

3.1.32
load controlled response
a riser response scenario in which the relevant loads acting on the section under evaluation will not be significantly relieved by global deformations of that section (i.e., loads are independent of deformation)

3.1.33
load effect
effect of a single load or combination of loads on the structure, such as stress, strain, deformation, displacement, motion, etc.

3.1.34
local buckling
buckling mode implying deformations of the cross-section.

NOTE This can be due to external pressure (hoop buckling) or moment (wrinkling) or a combination thereof.

3.1.35
low frequency vessel motion
motion response of the floating production system (FPS) at frequencies below wave frequencies, typically with periods ranging from 20 to 300 seconds

3.1.36
maintenance
total set of activities performed during the service life of the riser to preserve its function

3.1.37
manufacturer
Individual or organization that takes the responsibility for the manufacture of a riser component.

NOTE The manufacturer may subcontract one or more of the tasks under its responsibility.

3.1.38
ovalization
transformation from a circular to a slightly elliptic (oval) cross-section

3.1.39
purchaser
organization that buys the riser system on behalf of the user and/or operator or for its own use

3.1.40
resistance
ability of a component, a cross-section, or a member of the structure to withstand the imposed loads without failure, e.g., bending resistance, local buckling resistance

3.1.41
riser joint
joint consisting of a tubular member(s) with riser connectors at the ends

3.1.42
riser model
structural analysis model that is established from the tabulated data of the riser, to describe the actual riser, and used in global analysis of the riser system

3.1.43
riser system
the riser and all integrated components, including subsea and surface equipment

3.1.44
S-N curve
a plot of stress range (S) against the number of cycles (N) to failure obtained by cycling specimens to failure

3.1.45
ε-N curve
a plot of strain amplitude (ε) against the number of strain reversals (2N) to failure obtained by cycling specimens to failure using controlled strains

3.1.46
seamless pipe
tubular product fabricated without a welded longitudinal seam

NOTE Typically manufactured in a hot forming process by extrusion or drawing that can be followed by cold sizing or finishing to the desired shape, dimensions and properties.

3.1.47
service life
time period over which a riser is in active operation, which may be equal to or less than the design life

3.1.48
shakedown
a condition wherein an elastic-plastic material is loaded beyond the yielding point and has a limited plastic deformation, and the original elastic stress-strain line offsets with the limited permanent plastic strain if it is unloaded and reloaded again, eventually leading to some residual stress state, from which it subsequently responds elastically

3.1.49
slugging
a phenomenon in multiphase pipe flow where liquid and gas phases segregate into large predominantly liquid “slugs” and predominantly gas “bubbles” that propagate along the flowline/riser

3.1.50
sour service
service conditions with H_2S content exceeding the minimum specified by NACE MR0175/ISO 15156 at the design pressure

3.1.51
specified minimum ultimate strength
SMUS
minimum ultimate strength at room temperature prescribed by the specification or standard under which the material is purchased

3.1.52
specified minimum yield strength
SMYS
minimum yield strength at room temperature prescribed by the specification or standard under which the material is purchased

3.1.53
stress amplification factor
stress concentration factor
local peak stress in a component (including welds) divided by the nominal stress in the pipe wall at the location of the component

NOTE 1 This factor is used to account for the increase in the stresses caused by geometric stress amplifiers that occur in the riser component.

NOTE 2 For fatigue analysis of mechanical connectors this factor is defined as the local peak stress range in a component divided by the nominal stress range in the pipe wall.

3.1.54
stress intensity factor
a parameter that defines the stress state at a crack tip, in terms of global parameters such as of loads, geometry and crack size

3.1.55
stress joint
specialized riser joint designed with a tapered cross-section to control curvature and absorb bending stresses

3.1.56
stress range
the difference between stress maximum and stress minimum in a stress cycle

3.1.57
stroke
total vertical movements (upward and downward) of the riser relative to the FPS that is also the travel of the riser tensioner

NOTE Stroke is affected by environmental loads, functional loads (i.e., top tension, temperature and mean static vessel offset) and pressure.

3.1.58
subsea tree
assembly of valves attached to the uppermost connection of the subsea wellhead and used to control well production and isolation

3.1.59
subsea wellhead
assembly used during drilling, completion and production operations that has provisions to lock and seal the well tubing to a subsea BOP stack, to a subsea tree, to a high-pressure drilling riser or to a top-tensioned production riser

3.1.60
surface tree
device placed at the top of the riser string that provides flow control of the production and/or annulus bores during production (typically instead of a subsea tree)

3.1.61
temporary events
short duration events that occur during construction and operations that significantly deviate from normal operating conditions

3.1.62
tensioner system
device that applies a tension to the top-tensioned riser string while compensating for the relative vertical motion (stroke) between the FPS and the top of the deployed riser string

3.1.63
test pressure
internal pressure during field pressure testing of risers and/or riser components performed after installation and before start of operation

NOTE Field pressure testing of fabricated components may be to a lower pressure.

3.1.64
top tensioned riser
vertical or nearly vertical riser supported by top tension in combination with boundary conditions that allows for relative riser/vessel motions in the vertical direction and constrained to follow the horizontal vessel motion at one or several locations

3.1.65
tubing
pipe used in wells to conduct fluid from the well's producing formation into the subsea or surface tree

3.1.66
verification
examination to confirm that an activity, a product, or a service is in accordance with specified requirements

3.1.67
vessel offset
total lateral offset of the FPS, taking into account the static and dynamic forces from current, wind, and wave, including wave-frequency and low-frequency motions

3.1.68
vortex induced vibration
VIV
in-line and transverse oscillation of a riser in a current induced by the periodic shedding of vortices

3.1.69
vortex induced platform motions
VIM
in-line and transverse oscillation of a FPS in a current induced by the periodic shedding of vortices around the hull of the FPS

3.1.70
wave frequency motion
motion of the FPS at the frequencies of incident waves (i.e., typically with wave periods between 2 and 20 seconds)

3.1.71
wave scatter diagram
table listing occurrence of sea states in terms of significant wave height and wave peak period or mean up-crossing period

3.2 Symbols

A	pipe cross-section area (considering corrosion, wear and erosion allowances, see 5.2.1)
A_i	internal cross section of the pipe
A_o	external cross section of the pipe
a	fatigue ductility coefficient for low cycle fatigue
b	fatigue ductility coefficient for low cycle fatigue
D	nominal outside diameter of pipe
D_{max}	greatest measured diameter at any given cross section
D_{min}	smallest measured diameter at any given cross section
δ_0	ovality
E	Young's modulus
ε	bending-induced strain in pipe
ε_b	bending strain at which buckling occurs
ε_t	total strain fatigue for low cycle fatigue
ε_e	elastic strain amplitude for low cycle fatigue
f_c	collapse factor
F_D	design factor
F_{fat}	fatigue design factor
F_{sc}	safety class factor for LSD Method 2
$f_{sc,\varepsilon}$	safety class factor for strains
H_s	significant wave height;
I	moment of inertia of section (considering corrosion, wear and erosion allowances, see 5.2.1);
k	parameter to account for variability in pipe mechanical properties and wall thickness;
Kc	Keulegan-Carpenter number
M	moment in pipe;
M_{max}	plastic moment capacity;
M_p	plastic bending moment capacity of the pipe;
M_y	yield moment in pipe;
n_i	number of cycles at stress range S_i in each fatigue stress block;
N	number of cycles to failure at constant stress range, S ;
N_i	number of cycles to failure at constant stress range, S_i in each stress block;
p_b	burst pressure of the pipe;

p_c	collapse pressure;
p_e	external pressure;
p_{el}	elastic hoop buckling (collapse) pressure (instability) of pipe cross-section;
p_i	internal pressure;
P_y	yield pressure at collapse;
Re	Reynolds number
S	specified minimum yield strength (SMYS) of the pipe (same as σ_y);
S_i	constant stress range in each fatigue stress block;
σ_a	axial stress in the pipe wall;
σ_b	bending stress;
σ_e	von Mises equivalent stress;
σ_1, σ_2, σ_3	principal stresses;
σ_p	membrane stress;
σ_q	secondary stress;
σ_y	specified minimum yield strength of the pipe (same as *S*);
T	effective tension in pipe;
T_a	axial (material) tension in pipe;
T_y	yield tension in pipe;
t	pipe wall thickness used in design equations (nominal pipe wall thickness reduced for corrosion, wear and/or erosion as appropriate, see 5.2.1);
U	specified minimum ultimate strength of pipe;
ν	Poisson's ratio.

3.3 Abbreviated Terms

ALARP	as low as reasonably practical
ALS	accidental limit state
ALS	accidental limit state
AOD	argon oxygen decarburization
AUT	automated ultrasonic testing
A&R	abandonment and recovery
BOP	blow-out preventer
CP	cathodic protection
CRA	corrosion resistant alloy
CTOD	crack tip opening displacement
DSAW	double submerged arc welding
ECA	engineering criticality assessment
ERW	electric resistance welded
ESD	emergency shut-down
ET	eddy current testing
FAT	factory acceptance test
FBE	fusion bonded epoxy
FLS	fatigue limit state
FMC	full matrix capture (PAUT)
FMEA	failure mode and effects analysis
FPS	floating production system
FRP	fiber reinforced plastic
FSHR	free standing hybrid riser
GVI	general visual inspection
HAZ	heat-affected zone
HAZID	hazard identification
HAZOP	hazard and operability
HV	Vickers hardness
ID	inner diameter
IM	integrity management
ITBC	internal tie-back connector
ITP	inspection and test plan
IWEX	inverse wavefield extrapolation (PAUT)
LE	life extension

LSD	limit state design
MAOP	maximum allowable operating pressure
MODU	mobile offshore drilling unit
MPS	manufacturing procedure specification
MPI	magnetic particle inspection
MSL	mean sea level
MTR	material test report
NDE	nondestructive examination
OD	outer diameter
PAUT	phased array ultrasonic testing
PT	penetrant testing
QA/QC	quality assurance/quality control
QRA	quantitative risk analysis
ROV	remotely operated vehicle
RT	radiographic testing
SAF	stress amplification factor
SCR	steel catenary riser
SLS	serviceability limit state
SLWR	steel lazy wave riser
SMUS	specified minimum ultimate strength
SMYS	specified minimum yield strength
TCP	thermoplastic composite pipe
TDP	touchdown point
TDZ	touchdown zone
TFM	total focusing method (PAUT)
TLP	tension leg platform
TLS	test limit state
TTF	top tension factor
TTR	top tensioned riser
ULS	ultimate limit state
UNS	unified numbering system
VIM	vortex induced platform motions
VIV	vortex induced vibration
ULS	ultimate limit state
UT	ultrasonic testing
VT	visual testing (examination)

WPS	welding procedure specification
WSD	working stress design

4 Design Loads and Conditions

4.1 General

Riser systems are intended to provide for safe, reliable and economic production of oil and gas. All loads that are reasonably foreseeable should be considered in the design. HAZID, HAZOP and FMEA are useful tools to ensure that important scenarios are not missed, and they provide guidance for mitigation of risk.

The purpose of design is to prevent riser failure under various load effects such as stress, strain, pressure, bending moment, tension, fatigue damage, crack growth, etc. Load effects come from combinations of loads. Specific combinations of loads are referred to as load cases.

The determination of appropriate load cases requires a good understanding of the entire system and operating requirements for the various components and phases of operation. These operating loads and other parameters such as the design pressure are needed for design. The determination of all loads and load cases is the responsibility of the operator and should be documented in a design basis.

This recommended practice covers limit state design (LSD), and working stress design (WSD).

4.2 Loads

Loads are classified as functional, environmental, accidental, fatigue, or construction.

a) Functional loads are all loads resulting from the riser functioning normally in still water. Examples include weight, buoyancy, external hydrostatic pressure, internal pressure, thermal loads caused by content temperature, and seabed reactions.

b) Environmental loads are loads induced by the external environment, primarily combinations of wind, wave and current loads.

c) Accidental loads are loads caused by accidental occurrences that can reasonably be foreseen. Examples include abnormal environmental conditions, operational malfunction, failed mooring lines, flooded hull compartments, damaged tensioners, casing or tubing leaks, and loads from accidental impacts or collisions.

d) Fatigue loads are cyclic loads resulting in accumulated damage. Examples include loads due to FPS motions, direct wave and current loading on the riser, vortex-induced vibration (VIV) of the riser, vortex-induced motion (VIM) of the FPS, as well as flow related loads due to temperature and pressure cycling, and slugging.

e) Construction loads are loads that arise from riser system construction activities, including manufacturing, handling, transportation, installation, commissioning, maintenance, retrieval, and repair.

4.3 Design Load Cases

4.3.1 Strength

Design strength load cases are combinations of loads as defined in 4.2. Each load case should be assigned to one of the load case categories defined in Table 1, based on its overall annual probability of exceedance. The design strength load cases are defined as Operating, Extreme, Test and Survival categories in the WSD method.

When used in the context of LSD methods, the corresponding categories are referred to as limit states and are defined as serviceability limit state (SLS), ultimate limit state (ULS), test limit state (TLS) and accidental limit state (ALS). The categories are equivalent in either approach, as defined in Table 1.

Load case definitions should include all possible functional conditions, as well as riser and platform configurations. Example load combinations for strength design are given in Table 2.

Table 1 — Load Case Category Definitions

Category		Definition
WSD	**LSD**	
Operating	SLS	Maximum operational conditions and normal temporary events with combined annual probability of exceedance $>10^{-2}$
Extreme	ULS	Extreme operational conditions and abnormal temporary events with combined annual probability of exceedance $\leq 10^{-2}$
Test	TLS	Hydrostatic pressure test events only
Survival	ALS	Survival conditions or rare accidental loads with combined annual probability of exceedance $\leq 10^{-3}$

Table 2 — Examples of Strength Load Cases

Load Case	Environment Return Period [1]	Functional Load	Accidental Load	Load Case Category	
				WSD	**LSD**
1	Maximum construction	Construction / Installation	No	Operating	SLS
2	10-year	Maximum operating	No		
3	100-year	Maximum operating	No	Extreme	ULS
4	100-year	Extended shut in	No		
5	1,000-year	Extended shut in	No	Survival	ALS
6	Maximum test	Hydrostatic test pressure	No	Test	TLS
7	100-year	Maximum operating	Failed mooring line	Survival	ALS
8	10-year	Maximum operating	Flooded compartment		
9	10-year	Associated	Casing/ tubing leak		
10	100-year	Associated	Damaged tensioner		
…	Additional load cases as suit the situation				

Note 1 See Annex A for discussion.

For additional guidance on load cases for re-assessment of existing risers, refer to Section 9.

4.3.1.1 Intact Load Cases

Load cases 1 through 6 in Table 2 are examples of intact load cases. The environment associated with intact Operating/SLS load cases shall have a 1-year or greater return period. The selection of the appropriate return period can be different depending on the local environmental patterns, functional parameters and design conditions. Refer to Annex A for further discussion.

The environment associated with intact Extreme/ULS load cases shall be a 100-year return period event (annual probability of exceedance of 10^{-2}).

The environment associated with intact Survival/ALS load cases shall be a 1,000-year return period event (annual probability of exceedance of 10^{-3}). This is a robustness check to ensure that an environmental event more extreme than the Extreme/ULS event does not lead to catastrophic failure of the riser system.

This recommended practice assumes platforms are evacuated for intact Survival/ALS events and hence life safety is not at risk. For situations where platforms are not evacuated, a Survival/ALS event with a lower annual probability of exceedance should be used, based on site-specific information, risk assessments and regional guidance.

Events with combined annual probability of exceedance smaller than the Survival/ALS event probability can be ignored. See Annex A for further discussion.

4.3.1.2 Damaged Load Cases

The selected load cases should include accidental events where the FPS or riser support structure are damaged or malfunctioning in ways that could be detrimental to riser response. The environment associated with a damaged load case should produce the commensurate combined annual probability of exceedance, taking into consideration not only the likelihood of the damage occurring, but also the exposure time before the damage can reasonably be expected to be fully repaired.

Typically, the return period for a damaged case is one order of magnitude less than the associated intact load case (i.e., 10-year return period for Extreme/ULS, 100-year return period for Survival/ALS), but it could be more or less depending on the exposure time and the type of damage.

Refer to the relevant FPS design specifications (e.g., API RP 2T, API RP 2FPS, API RP 2SK) for the appropriate damaged scenarios for FPS hull and mooring systems. Refer to Annex A for more discussion.

4.3.2 Fatigue

Fatigue represents an additional potential failure mode or limit state. Sources of fatigue include waves, currents (VIV, VIM), thermal cycling, pressure fluctuations and slugging. See Annex A for additional information on slugging.

Examples of fatigue load cases are given in Table 3. Construction cases cover the range of construction activities defined in 4.2 in their associated environmental conditions with the associated motions of the FPS or construction vessel as applicable. The fatigue response of all riser configurations expected during normal operations should be assessed.

Table 3 — Examples of Fatigue Load Cases

Case	Environment	Functional Loads
Construction	Associated	Associated
Wave induced fatigue	Wave scatter diagram	Normal operating
Vortex induced vibration (VIV)	Current scatter diagram	Normal operating
Vortex induced motion (VIM)	Current scatter diagram	Normal operating
Single storm event (wave fatigue)	Extreme/ULS storm Survival/ALS storm	Associated
Single current event (VIV, VIM fatigue)	Extreme/ULS current Survival/ALS current	Associated
Flow induced fatigue (e.g., thermal cycling, slugging, pressure fluctuations)	Associated	Normal operating

5 Design of Pipe

5.1 Overview

5.1.1 Objective

This section sets out design criteria for the pipe portion of the riser for the load categories defined in Section 4. The design shall ensure that the riser pipe has adequate structural resistance by meeting the pipe capacity requirements defined in 5.2, the pressure load requirements of 5.3, and the combined load requirements of 5.4 or 5.5. The fatigue resistance of the riser shall meet the requirements of 5.6. Riser interference requirements are in 5.7.

Refer to Section 6 for additional requirements for the design of riser components other than pipe, including ancillary equipment such as VIV suppression devices and buoyancy modules.

For combined load capacity calculations, either the working stress design (WSD) method or limit state design (LSD) method can be used to check the riser design against linear elastic allowable strength criteria. The WSD method, which uses primary membrane stress criteria, has been used as the traditional means to design and analyze risers (API RP 2RD, first edition [S11]), while the LSD method was introduced more recently (API Std 2RD, second edition [S12]). Both methods are acceptable. Refer to Annex A for additional guidance and a flowchart of the design process. Design criteria for WSD are defined in 5.4. Design criteria for LSD are defined in 5.5.

There are instances where it is acceptable to exceed the allowable moment computed using yield moment. In load-controlled regions of the riser, the allowable moment capacity can be computed using the plastic moment according to LSD Method 2. This is a limit state design approach.

Where total strain exceeds 0.5% on the OD, refer to 7.7 for additional requirements for material qualifications.

The values of axial load, pressure, bending moment and bending strain to be used in the design check equations may be either the most probable maximum values, or the expected maximum values, corresponding to the load case being assessed.

It is prudent to conduct an ECA to determine whether weld inspection criteria are achievable. DNV-RP-F108 may be used.

5.1.2 Design Format

5.1.2.1 Working Stress Design (WSD)

The design format sets limits on von Mises equivalent stress calculated by combination of the principal stress components at each critical section under the applied loads or load effects, to a fraction of the yield strength of the component. The limit is set in the form:

$$\text{von Mises equivalent stress} < F_D \times \sigma_y,$$

where

F_D is a design factor that is not to exceed 1.

σ_y is the specified minimum yield strength of the component.

The design factor depends on the load case and is different for Operating, Extreme, Test and Survival load categories (see Section 4).

5.1.2.2 Limit State Design (LSD)

The design format sets limits on loads or load effects to a fraction of the capacity of the component to resist the load or load effect. The limit is set in the form:

$$\text{Load or Load Effect} \leq F_D \times \text{Capacity},$$

where

F_D is a design factor that is not to exceed 1.

The design factor depends on the type of load and can be different for SLS, ULS, TLS and ALS categories.

Refer to Annex C for example design calculations using each of the combined load calculation methods.

5.1.3 Safety Class Methodology

All riser components shall be categorized into a suitable safety class based on human, environmental and economic consequences of failure that in turn, depend on two main considerations: location and contents.

When the riser component is at sufficient distance from frequent human contact, or when the content is not harmful, such as non-flammable, non-toxic liquid or gas, risk of human injury is at a minimum. However, internal pressurization and/or elevated temperature of non-harmful contents can raise the risk of human injury depending on location.

Given these considerations, three safety classes are defined in Table 4 for risers with pipeline or well access. The operator is responsible for assigning safety class and may choose a higher safety class based on any potential economic consequences. Safety class should be clearly documented in the design basis.

Safety class categorization should be based on thorough safety assessments conducted by the Operator, including HAZID, HAZOP and other appropriate methods.

Table 4 — Safety Classes

Safety Class	Location	Contents
Low	Unmanned	Non-flammable, non-toxic liquid or gas
Normal	Unmanned	Flammable or toxic liquid or gas
	Manned	Non-flammable, non-toxic liquid or gas
High	Manned	Flammable or toxic gas or liquid

Risers that are in testing or temporary state with no pipeline or well access may be considered as a low safety class regardless of location or contents, except for manned locations where flammable or toxic gas contents are present in other systems at risk of collateral damage. This temporary state exception should be considered as normal safety class.

The state of the contents being either liquid or gas is defined by its condition at ambient pressure and temperature.

Absent of appropriate risk analysis, unmanned locations may be assumed to be a horizontal distance greater than 500m (1640ft) from frequent human contact.

Safety class factors are specified in Section 5 for each limit state and reflect safety classes defined in Table 4. Refer to Annex A for more information on safety class.

5.2 Pipe Capacity

5.2.1 General

The capacity formulae presented are intended to represent the minimum capacity. Capacity is a function of the product specification. The product specification should define properties (strength, fracture toughness, etc.) over the range of temperatures anticipated in service. Capacity calculations shall use the properties corresponding to the temperature of the applicable load case (see 7.5).

The wall thickness shall take into account corrosion and wear/erosion allowance except for initial hydrotesting, or construction activities performed before such allowance is consumed (see Annex B). For clad pipe, refer to Section 7.

5.2.2 Burst Pressure

The minimum burst pressure of pipe can be determined by Equation (1):

$$p_{\mathrm{b}} = k\left(S+U\right)\ln\left(D/(D-2t)\right) \tag{1}$$

where

k is a parameter to account for variability in mechanical properties and wall thickness, and is equal to 0.45 for API Spec 5L or API Spec 5CT pipe and can be increased to 0.5 provided the requirements for qualification of increased minimum burst pressure in API RP 1111 are met;

D is the nominal outside diameter of the pipe;

t is the nominal thickness of the pipe reduced for corrosion, wear and/or erosion as appropriate (see 5.2.1);

S is the specified minimum yield strength (SMYS) of the pipe;

U is the specified minimum ultimate strength (SMUS) of the pipe.

The minimum burst pressure can also be determined experimentally using the procedure in API RP 1111.

5.2.3 Collapse Due to External Pressure

The collapse pressure can be determined by Equation (2).

$$p_{\mathrm{c}} = \frac{P_{\mathrm{y}}\, p_{\mathrm{el}}}{\sqrt{P_{\mathrm{y}}^2 + p_{\mathrm{el}}^2}} \tag{2}$$

where

P_{y} is the yield collapse pressure, given by Equation (3);

P_{el} is the elastic buckling collapse pressure, given by Equation (4).

$$P_{\mathrm{y}} = 2S\left(\frac{t}{D}\right) \tag{3}$$

$$p_{el} = \frac{2\,E\left(\frac{t}{D}\right)^3}{1-\nu^2} \tag{4}$$

where

E is Young's modulus;

ν is Poisson's ratio.

5.2.4 Buckling Collapse Due to Pure Bending

Pure bending can result in wrinkling of the pipe wall or flattening of the cross-section. Both conditions are known as buckling due to bending. The resulting bending strain from buckling shall be calculated using Equation (5).

$$\varepsilon_{\mathrm{b}} = \frac{t}{2D} \tag{5}$$

Deformation of the cross-section does not reduce the internal pressure capacity or the tensile capacity unless strains are large enough to cause material rupture.

5.2.5 Tension

The tension capacity can be determined by Equation (6).

$$T_{\mathrm{y}} = S\,A \tag{6}$$

where

$A = \pi\,(D - t)\,t$, the pipe cross-section area.

5.2.6 Yield Moment

The moment that corresponds to a membrane stress (i.e., at mid-wall) equal to yield can be determined by Equation (7).

$$M_y = \frac{2SI}{D-t} \approx \frac{\pi}{4} S(D-t)^2 t \tag{7}$$

Where

$I = \pi/64\,[D^4 - (D-2t)^4]$, the moment of inertia of the pipe.

The yield moment is used in the LSD Method 1 combined load formulae in 5.5.2.

5.2.7 Plastic Moment

The bending moment capacity corresponds to yielding of the cross-section. The plastic moment, assuming elastic perfectly-plastic material, can be determined by Equation (8).

$$M_p = \frac{S}{6}\left(D^3 - (D-2t)^3\right) \approx S(D-t)^2 t = \frac{4}{\pi} M_y \tag{8}$$

Plastic moment is used in the combined load formulae of LSD Method 2 in 5.5.3.

5.3 Design for Pressure

5.3.1 Internal Pressure

The net internal overpressure shall not exceed the pressure determined by Equation (9).

$$p_i - p_e \le F_D\, p_b \tag{9}$$

where

p_e is the external pressure;

p_i is the internal pressure;

F_D is a design factor and is given by Equation (10).

$$F_D = \begin{cases} 0.75\ Hydrostatic\ test \\ 0.67\ Incidental\ pressure \\ 0.60\ Design\ pressure \end{cases} \tag{10}$$

For risers that are part of a pipeline system, check also the pipeline's pressure rating (refer to API RP 1111). The hydrostatic test pressure of the riser shall not exceed that of the pipeline when they are tested together.

Refer to 5.2.1 and Annex B for guidance on use of wall thickness allowance.

5.3.2 External Pressure

The net external overpressure shall not exceed that given by Equation (11).

$$p_e - p_i \le F_D\, p_c \tag{11}$$

where

Pc is the collapse pressure given by Equation (2)

F_D is a design factor, given by Equation (12).

$$F_D = \begin{cases} 0.6 & cold\ expanded\ pipe\ (e.g. DSAW) \\ 0.7 & seamless\ or\ ERW\ pipe \end{cases} \tag{12}$$

Under some circumstances for cold expanded pipe, credit can be taken for partial recovery of compressive yield strength by heat treatment to at least 233 ºC (450 ºF) for several minutes. Such heat treatment may be provided during the fusion bonded epoxy (FBE) coating process of the pipe, provided temperature and duration of heating is carefully controlled. In such cases, the collapse factor of 0.6 may be raised to no more than 0.7. The proposed increase in design factor shall be validated through a testing program performed by the FBE coating contractor using the same or similar pipe.

5.3.3 Combined Bending and Pressure

Bending strain limits shall be set to avoid collapse of pipe cross-section under combined bending and overpressure. The criteria are given by Equations (13) and (14). Note that the combined pressure and bending strain criteria given herein is independent of the load case (no design factor F_D is used) and shall be satisfied in inelastic response regardless of the load case.

$$\varepsilon \leq \frac{\varepsilon_b}{(1+20\delta_0).f_{sc,\varepsilon}} \quad \text{(internal overpressure)} \tag{13}$$

$$\varepsilon \leq \frac{\varepsilon_b}{(1+20\delta_0).f_{sc,\varepsilon}}\left(1 - \frac{p_e - p_i}{f_c\ p_C}\right) \quad \text{(external overpressure)} \tag{14}$$

Where

Pc is the collapse pressure given by Equation (2)

ε is the bending-induced strain in the pipe;

ε_b is the pure bending collapse strain, given by Equation (5)

δ_0 is pipe initial ovality (initial departure from circularity), given by Equation (15) plus any permanent ovality resulting from inelastic cycling response

$$\delta_0 = \frac{D_{\max} - D_{\min}}{D_{\max} + D_{\min}} \tag{15}$$

The initial ovality, δ_0, shall not be taken as less than 0.0025 (0.25 %). Ovalization caused during the construction and installation phase shall be included in the ovality. Ovalization due to external pressure or moment in the as-installed condition shall not be included so long as the response is elastic. However, for inelastic cyclic response resulting in progressive ovality, the resulting permanent ovality should be included. The resulting permanent ovality may be determined by testing, finite element analysis, analytical solutions, or empirical solutions.

$f_{sc,\varepsilon}$ is a safety class factor for strains provided in Table 5. Refer to 5.1.3 and Annex A for additional information on safety class.

Table 5 — Safety Class Factor for Strains, $f_{sc,\varepsilon}$

Low	Normal	High
2.0	2.5	3.3

f_c is the collapse factor for use with combined pressure and bending loads given by Equation (16).

$$f_c = \begin{cases} 0.6 & \text{cold expanded pipe (e.g. DSAW)} \\ 0.7 & \text{seamless pipe} \end{cases} \tag{16}$$

The bending strain in Equations (13) and (14) shall include an allowance for strain concentrations where appropriate, such as at discontinuities.

In general, average geometric properties and linear elastic material properties may be used in global analysis to assess stress and strains. If the calculated stresses exceed the yield stress, then nonlinear material properties shall be used to assess strains. Appropriately selected material properties shall be used to conservatively predict the maximum responses. The upper-bound nonlinear material properties, leading to increased stiffness, may be used to establish the loads and lower-bound properties, leading to lower stiffness, may be used to determine the strains.

If the total nominal strain in any direction (excluding strain concentration) due to installation and operations exceeds 0.5% at the OD surface, the additional requirements for material qualifications in 7.7 shall apply. In addition, fracture assessment is required.

For further guidance on the use of these formulae, refer to API RP 1111.

5.3.4 Collapse Propagation

Design for collapse propagation shall refer to API RP 1111.

5.4 Working Stress Design Criteria

5.4.1 Stresses to Consider

The three principal stresses shall be calculated at all critical locations in the riser. For axisymmetric geometries like plain pipe, the principal stresses will usually be in the axial, hoop and radial directions. For components with non-axisymmetric geometry, the directions may be different. The principal stress components shall be classified as one of the following:

Primary	Any normal or shear stress that is necessary to have static equilibrium of the imposed forces and moments. A primary stress is not self-limiting. Thus, if a primary stress substantially exceeds the yield strength, either failure or gross section yielding will occur.

	Membrane	σ_p is the average value across the thickness of a solid section excluding the effects of discontinuities and stress concentrations. For example, the general primary membrane stress in a pipe loaded in pure tension is the tension divided by the cross-sectional area. σ_p may include global bending as in the case of a simple pipe loaded by a bending moment.
	Bending	σ_b is the portion of the primary stress proportional to the distance from the centroid of a cross-section, excluding the effects of discontinuities and stress concentrations.
Secondary	σ_q any normal or shear stress that develops as a result of material restraint. This type of stress is self-limiting, which means that local yielding can relieve the conditions that cause the stress, and a single application of load will not cause failure.	

Note that a principal stress component can be separated into more than one stress category. For example, the bending stresses in the sag-bend of a catenary riser (made of ductile metals) may be considered as secondary stresses for strength assessment if it can be demonstrated that they are displacement controlled. Otherwise, they should be considered as primary stresses. Bending stresses (and strains) that exceed yield in this case do not diminish plain pipe's capacity as a pressure barrier.

If the bending can be demonstrated as secondary, two options are available. A condition factor of 0.85 can be applied to the bending moment when computing the primary membrane stress (refer to Annex A). Alternatively, nonlinear material properties may be used to assess the extent of yielding so long as the bending strains do not exceed the allowable limit in 5.3.3.

5.4.2 Combined Stresses

Principal stress components at each critical section shall be combined using the von Mises criterion defined by Equation (17).

$$\sigma_e = \frac{1}{\sqrt{2}}\sqrt{(\sigma_1 - \sigma_2)^2 + (\sigma_2 - \sigma_3)^2 + (\sigma_3 - \sigma_1)^2} \tag{17}$$

where

σ_e is the von Mises equivalent stress;

$\sigma_1, \sigma_2, \sigma_3$ are the principal stresses.

Depending on the geometry and the loading, there may be an equivalent combined stress for each category of stress (primary membrane, primary membrane plus bending, and primary membrane plus bending plus secondary) at each section.

5.4.3 Allowable Stresses

The von Mises equivalent stresses shall be less than the allowable stresses defined by the right-hand side of the following inequalities.

$$\left(\sigma_p\right)_e < F_D \sigma_y \tag{18}$$

$$\left(\sigma_p + \sigma_b\right)_e < 1.5 F_D \sigma_y \tag{19}$$

$$\left(\sigma_p + \sigma_b + \sigma_q\right)_e < 3.0 F_D \sigma_y \tag{20}$$

where

σ_y is the specified minimum yield strength (SMYS) of the material, same as *S* in 5.2;

F_D is the design factor, given in Equation (21).

$$F_D = \begin{cases} 0.67 \text{ Operating} \\ 0.8 \text{ Extreme} \\ 0.9\ hydrostatic \text{ Test} \\ 1.0 \text{ Survival} \end{cases} \tag{21}$$

5.4.4 Allowable Stress in Plain Pipe

For plain pipe, typically the three principal stress components of primary membrane stress (average stress across the wall of the pipe) are in the axial, hoop and radial directions and are noted as σ_{pz}, $\sigma_{p\theta}$ and σ_{pr}, respectively. Therefore, the primary membrane stress criterion shall not exceed that given in Equation (22).

$$\frac{1}{\sqrt{2}}\sqrt{\left(\sigma_{pr} - \sigma_{p\theta}\right)^2 + \left(\sigma_{p\theta} - \sigma_{pz}\right)^2 + \left(\sigma_{pz} - \sigma_{pr}\right)^2} \leq F_D \sigma_y \tag{22}$$

For thick-walled pipe, these principal stress components can be calculated using the following formulae

$$\sigma_{pz} = \frac{T_a}{A} \pm \frac{M}{2I}(D - t) \tag{23}$$

$$\sigma_{p\theta} = (p_i - p_e)\frac{D}{2t} - p_i \tag{24}$$

$$\sigma_{pr} = \frac{\left(p_e D + p_i (D - 2t)\right)}{2(D - t)} \tag{25}$$

where

p_i is the internal pressure;

p_e is the external pressure;

$\mathrm{A} = \pi(\mathrm{D} - \mathrm{t})\mathrm{t}$, the cross-section area of the pipe;

T_a is the true wall tension in the pipe;

M is the global bending moment in the pipe; (including condition factor if applicable)

$\mathrm{I} = \frac{\pi}{64}(\mathrm{D}^4 - (\mathrm{D} - 2\mathrm{t})^4)$, the moment of inertia of the pipe.

Note that primary membrane plus bending and primary membrane plus bending plus secondary stress criteria never control the design for plain pipe.

An alternate formula for the primary membrane stress is given below, which can be obtained by substituting Equations (23), (24), and (25) into Equation (22) and performing some algebra.

$$\sigma_e^2 = \left[\frac{\sqrt{3}(p_i - p_e)D(D - 2t)}{4(D - t)t}\right]^2 + \left[\frac{T}{A} \pm \frac{M(D - t)}{2I}\right]^2 \leq \left(F_D \sigma_y\right)^2 \tag{26}$$

where

$T = T_a - p_i A_i + p_e A_o$, the effective tension in the pipe;

$A_i = \pi (D - 2t)^2/4$, the inside area of the pipe;

$A_o = \pi D^2/4$, the outside area of the pipe.

Refer to 5.2.1 for guidance on use of wall thickness allowance in these equations.

NOTE: For TTR design, keeping the effective tension positive along the riser requires a sufficient nominal tension to prevent global buckling of the TTR.

5.5 Load Limit State Design Criteria – Methods 1 and 2

5.5.1 Fundamentals

Load limit state design criteria are generally applicable when the relevant loads acting on the section under evaluation will not be significantly relieved by global deformations of that section. Load limits may also be used even if the riser response is deemed displacement controlled.

In the following sections, limits are set on combined axial, pressure and bending loads for SLS, ULS, ALS and TLS categories. Since pressure and temperature are specified for each load case, the combined loading criteria set limits on longitudinal load due to axial and bending loads.

Two methods of combined load criteria are set out. Method 1 is calibrated to yield on combined membrane load and can be considered as comparable to WSD. Method 2 allows higher bending moments and accounts for the presence of plasticity; however, the bending strains shall not exceed the allowable limit using nonlinear material properties in 5.3.3.

The operator may choose to set more restrictive limits in some cases.

Refer to 5.3.3 for guidance on material modeling.

5.5.2 Method 1

The load combinations and associated design factors for Method 1 are applicable to all safety classes and shall satisfy Equations (27) and (28).

$$\left|\frac{T}{T_y}\right| + \left|\frac{M}{M_y}\right| \leq \sqrt{F_D^2 - \left(\frac{p_i - p_e}{p_b}\right)^2} \quad \text{(internal overpressure)} \tag{27}$$

$$\left|\frac{T}{T_y}\right| + \left|\frac{M}{M_y}\right| \leq \sqrt{F_D^2 - \left(\frac{p_e - p_i}{p_c}\right)^2} \quad \text{(external overpressure)} \tag{28}$$

where

$T = T_a - p_i A_i + p_e A_o$, the effective tension in the pipe;

$T_a = \sigma_a A$, the true wall tension in the pipe;

σ_a is the axial stress in the pipe wall;

$A_i = \pi\,(D - 2t)^2/4$, the inside area of the pipe;

$A_o = \pi\, D^2/4$, the outside area of the pipe.

$A = \pi(D - t)t$, the cross-section area of the pipe;

M is the moment in the pipe;

F_D is a design factor, given by Equation (29).

$$F_D = \begin{cases} \text{0.8 SLS, ULS internal and external overpressure} \\ \text{0.9 ALS external overpressure for } p_e\text{-}P_i > 0.5\, p_c \\ \text{0.9 TLS hydrostatic test} \\ \text{1.0 ALS otherwise} \end{cases} \tag{29}$$

Note: Equations (27) and (28) are valid up to $(p_i\text{-}p_e)/p_b$ *or* $(p_e\text{-}p_i)/p_c < F_D$

If the bending can be demonstrated as secondary, it can be multiplied by a condition factor of 0.85 (Refer to Annex A).

5.5.3 Method 2

Method 2 limits axial load based on yield tension including the effect of internal pressure and plastic moment. The load combinations and associated design factors shall satisfy Equations (30) and (31).

$$\left|\frac{M}{M_p}\right| \le \sqrt{F_D^2 - \left(\frac{p_i - p_e}{p_b}\right)^2}\; cos\left(\frac{\pi}{2}\frac{\frac{T}{Ty}}{\sqrt{F_D^2 - \left(\frac{p_i - p_e}{p_b}\right)^2}}\right) . \frac{1}{F_{sc}} \quad \text{(internal overpressure)} \tag{30}$$

$$\left|\frac{M}{M_p}\right| \le \sqrt{F_D^2 - \left(\frac{p_e - p_i}{p_c}\right)^2}\; cos\left(\frac{\pi}{2}\frac{\frac{T}{Ty}}{\sqrt{F_D^2 - \left(\frac{p_e - p_i}{p_c}\right)^2}}\right) . \frac{1}{F_{sc}} \quad \text{(external overpressure)} \tag{31}$$

where

F_D is a design factor, given by Equation (32).

$$F_D = \begin{cases} \text{0.8 SLS, ULS} \\ \text{0.9 TLS hydrostatic test} \\ \text{1.0 ALS} \end{cases} \tag{32}$$

F_{SC} is a safety class factor given in Table 6. Refer to 5.1.3 and Annex A for additional information on safety class.

Table 6 — Safety Class Factor, F_{SC}

Low	Normal	High
1.04	1.14	1.26

NOTE: Equations (30) and (31) are valid up to $(p_i-p_e)/p_b$ or $(p_e-p_i)/p_c < F_D$

Method 2 allows stresses beyond yield and can result in relatively high strains in some circumstances, such as ratcheting. The limit is set by maintaining cross-sectional integrity (i.e., pipe section does not collapse). This is addressed by the criteria in 5.3.3, using appropriate nonlinear material property modeling.

5.6 Fatigue

5.6.1 General

Fatigue assessment shall address all cyclic loading, including cycles with inelastic deformation. Corrosion allowance should be taken into consideration in fatigue analysis (refer to 5.2.1 and Annex B).

The riser design shall meet the requirements for long-term wave and current scatter diagram fatigue (5.6.2) as well as short-term single-event fatigue (5.6.3).

Long-term and short-term fatigue assessments shall include all cycles in the elastic range (i.e., high-cycle fatigue) (5.6.1.1) as well as any cycles in the inelastic range (i.e., low-cycle fatigue) where the stress amplitude exceeds yield (5.6.1.2). Such cycles could occur in service due to environmental loading, or during installation (e.g., pipe reeling and unreeling).

High-cycle and low-cycle fatigue damage shall be added together to obtain the total fatigue damage for both long-term fatigue (5.6.2) and short-term fatigue (5.6.3) assessments.

Hot spot strains can be considered using notionally elastic stresses if the total range is less than twice yield and shakedown occurs. Plasticity during reeling and unreeling is displacement controlled and is subject to low-cycle fatigue (5.6.1.2).

5.6.1.1 High-Cycle Fatigue

High-cycle fatigue damage due to cycles in the elastic range shall be calculated using an S-N approach. The S-N curve used for fatigue design of each riser component should be qualified for the intended service conditions, including internal fluids, level of cathodic protection, post-yield conditions, etc.

$$N = a\,S^{-m} \tag{33}$$

where

S is the cyclic stress range
N is the number of cycles to failure at stress range *S*
a, m are the fatigue curve coefficients

Long-term or short-term fatigue damage should be calculated using the Palmgren-Miner rule as given in Equation (34).

$$Damage = \sum_{i=1}^{K} \frac{n_i}{N_i} \tag{34}$$

where

n_i is the number of cycles at stress range S_i in each fatigue stress block (one cycle in rain-flow cycle counting or a number of cycles of a specified stress range in a histogram or a fatigue sea state in a frequency domain analysis);

N_i is the number of cycles to failure at stress range S_i in each fatigue stress block;

K is the number of fatigue stress blocks.

Parent material fatigue properties are influenced by mean stress. High mean stress will increase the fatigue damage and reduce the fatigue life. Commonly accepted methods used to account for the effect of the mean stress on the fatigue damage include the Goodman mean stress correction method and the Gerber mean stress correction method. Many fatigue curves have been adjusted for or inherently include the effects of mean stress and no further adjustment is required when using these curves. However, if the fatigue curve being used does not account for the effects of mean stress, then an adjustment of the mean stress effects should be included in the analysis.

5.6.1.2 Low-Cycle Fatigue

Low-cycle fatigue damage due to cycles in the inelastic range should be calculated using a strain *vs.* number of cycles to failure (ε-N) approach or using other methods or empirical means. Refer to Annex A for additional guidance.

5.6.2 Long-term Fatigue

The total long-term fatigue damage shall be obtained by simple summation of the damage from all long-term events, in-service as well as during construction (e.g., load-out, reeling, transport, installation, testing, commissioning).

> NOTE: Typically, construction fatigue is limited to a specified range of allowable damage that is consistent with the specific circumstances for loadout, transport, and installation. The remainder reserved for in-service fatigue. Typically, construction fatigue is around 5-10% of the allowable damage but in some situations, it may be much greater. Regardless, the construction damage budget needs to be estimated ahead of time, incorporated into the design and construction contracts, and tracked through the construction phase.

The total accumulated damage, D, over the design life of the riser shall not exceed the limit given in Equation (35).

$$D \leq \frac{1}{F_{fat}} \tag{35}$$

F_{fat} is the fatigue design factor given in Table 7.

All riser components are assumed to be permanently installed for the duration of the riser service life with all inspections being performed in-situ unless a riser is scheduled to be pulled regularly and inspected in

dry conditions throughout its service life (e.g., a FPS drilling riser between wells). Such risers shall be denoted as non-permanent if they meet the all of the following conditions:

- Inspections are performed in dry conditions at regular intervals when the riser is retrieved for operational purposes;
- The maximum inspection interval is based on operational needs and agreed with the regulator;
- Inspections include -
    - internal and external visual inspection;
    - external surface NDE (magnetic particle or liquid penetrant);
    - volumetric NDE (ultrasonic and/or radiographic) of critical welds;
    - wall thickness measurements of critical joints.

Such risers are designated non-permanent and may use a reduced fatigue safety factor, F_{fat}. In no case shall the fatigue safety factor, F_{fat}, be less than half the values listed in Table 7.

Table 7 — Fatigue Design Factor, F_{fat}

Safety Class	F_{fat}
Low	6
Normal	6
High	10

5.6.3 Single Event Fatigue

A significant amount of fatigue damage can result from a single environmental event (refer to 4.3.2 and Annex A). The criteria for single-event fatigue are intended as a demonstration of robustness of the design to extraordinary events not represented in the long-term fatigue analysis because their probability of occurrence is so low. It is not cumulative with long-term fatigue, which represents the expected fatigue damage.

The accumulated damage, *D*, in any single Extreme/ULS event or Survival/ALS event shall not exceed the limits stated in Equations (36) and (37) respectively.

$$D \leq \frac{1}{F_{fat}} \quad \textit{for a single Extreme / ULS event} \tag{36}$$

$$D \leq 1 \quad \textit{for a single Survival / ALS event} \tag{37}$$

The duration of each extreme event should be chosen to account for the conditions in the given geographical area. Refer to Annex A for additional guidance.

5.6.4 Engineering Criticality Assessment

Fracture mechanics-based assessments (e.g., Paris crack growth law and end-of-life fracture) should be performed as the technical basis for establishing weld flaw acceptance criteria and inspection intervals for all components. This analysis is commonly referred to as an engineering criticality assessment (ECA). For components that can be reliably inspected in place for cracks, the maximum inspection interval should be

based on the shorter of 1/5 of the time required for a reliably detectable crack to grow to failure, or when 0.1 accumulated damage is reached.

For permanent components that cannot be reliably inspected in place for cracks, the ECA in-place fatigue crack growth assessments should be based on half the pertinent Fatigue Design Factor from Table 7, but no less than 2. The methodology of BS 7910 or a similar industry-recognized guideline should be used to evaluate the smallest flaw during fabrication that can grow to a critical size during operation, including handling, installation, testing and commissioning. The ECA should address the cumulative potential for fatigue crack growth and ductile tearing, including environmental effects, after fabrication. The ECA should also address surface-breaking and near-surface embedded flaws for the outside and inside surfaces. The NDE should be able to detect and size the flaws identified by the ECA reliably.

Accurate understanding of the fracture toughness and crack growth rate under cyclic loading is necessary for the ECA. The designer should obtain these values with an understanding of the implications of the environment and load conditions under which the component is operating.

Refer to DNV-RP-F108 for fracture control of riser girth welds subject to cyclic plastic deformation.

5.7 Interference

The riser system design should include analysis of potential interference with other risers, umbilicals, mooring lines, tendons, the FPS hull, or any other potential obstructions. All phases of construction and operation should be considered. There are four categories of permissibility in relation to the severity of the interference or contact allowed between a riser and any obstruction. The categories and associated requirements are defined in Table 8.

The design shall satisfy the interference categories assigned to environmental conditions in Table 9, which distinguishes between storms (e.g., winter storms, hurricanes).and current events (e.g., the loop current in the Gulf of Mexico, the Gulf Stream, other oceanic circulation currents).

Table 8 — Riser Interference Categories and Requirements

Interference Category	Requirements
A	A minimum clearance shall be maintained equal to the sum of the diameters[1] of the riser and any adjacent tubular obstruction (e.g., riser, umbilical, mooring, tendon), or two-times the riser diameter[1] for other obstructions (e.g., FPS hull structure).
B	No contact shall be allowed.
C	Contact should be avoided. If there is contact, there shall be no damage to the riser or any of its appurtenances or the obstruction contacted, and no repairs required.
D	Contact should be avoided. If there is contact, there shall be no damage that leads to catastrophic failure of the riser or the obstruction contacted, nor escalation of damage or failure to other systems, including the FPS hull or mooring systems. Repairs or replacement may be required.

NOTE 1 – Diameter includes any insulation, buoyancy, or appurtenances that affect riser integrity.

Table 9 — Riser Interference Categories for Different Environments

Environmental Event Return Period	Interference with other risers or umbilicals		Interference with other obstructions (e.g., FPS hull, mooring lines, tendons, etc)	
	Storm Events	Current Events	Storm Events	Current Events
Construction Activities	A	B	A	B
10-year or less	A	B	A	B
100-year	A	C	A	B
1,000-year	A	D	A	C

Refer to Annex A for additional guidance on how to perform interference analysis.

6 Design Criteria for Components

6.1 General

A riser is an assembly of pipe (rigid or flexible) and components. Riser components are usually differentiated between those in the direct load path and those not in the direct load path. In addition, riser components have functionality requirements that are independent of static load and fatigue requirements.

Components in series with riser pipe that experience the same internal and external pressure loads as the pipe component are designated pressure containing components. Examples include connectors, stress joints, flexible joints, wellhead connectors, surface wellheads. Riser systems may be comprised of multiple concentric pipes where the pressure rating and loads vary.

Other non-pressure-containing components and ancillary equipment considered to be part of the riser system include riser tensioning systems, buoyancy modules, and VIV suppression devices. Such components should be designed to the same allowable utilization level and load cases as the riser pipe if the failure of the ancillary equipment would impact the integrity of the riser pipe; however, different design criteria than that for the pipe may be used.

Riser components have specific functional requirements in addition to having strength and fatigue capacities. It is not the intent of this Recommended Practice to provide all functional requirements for riser components or specify respective values, but to highlight fundamental functional requirements that differentiate each component's contribution to an overall riser system.

Table 10 summarizes riser components and their load path category (Table 11), typical functionality, recommended robustness features, and recommended standards that should be applied. The robustness features listed are recommended to minimize system risks and provide means to service the components with minimal downtime. Reference standards are included in addition to the applicable sections of this Recommended Practice, but other standards may also be applicable depending on the details of the component design. The riser design basis should reflect the specific standards to be used.

Table 10 — Riser Components

Component	Category (Table 11)	Functionality	Robustness Features	Reference Standards
Flanged Connection	A	Multiple make and break cycles with no permanent deformation Generate preload and maintain sealability up to extreme load cases.	Static strength exceeds pipe Internal pressure loss before exceeding allowable stress	API Spec 16F, API Std 17G
Threaded Connection	A	Multiple make and break cycles with no permanent deformation. Provide quicker makeup than flange connection. Generate preload and maintain sealability up to extreme load cases.	Static strength exceeds pipe Internal pressure loss before exceeding allowable stress	API Std 17G
Mechanical Connection (other)	A	Multiple make and break cycles with minimal to no permanent deformation. Provide quicker makeup than flange connection. Generate preload and maintain sealability up to extreme load cases.	Static Strength exceeds pipe Internal pressure loss before exceeding allowable stress	API Spec 6A
Tensioner System	B	Provide adequate tension range, axial stiffness, up-stroke and down-stroke for all design environments.	Able to operate with one cylinder out of service or tensioner stroke bottoming out	ASME Sec, VIII Div 2

Component	Category (Table 11)	Functionality	Robustness Features	Reference Standards
Tensioner Joint	A	Provide variable attachment points for tensioner	Static strength & fatigue life exceed pipe	
Keel Joint	A	Allow riser to be laterally supported by the keel guide, while freely moving axially	Static Strength exceeds pipe	
Tapered Stress Joint	A	Provide adequate transition of loads without damaging the wellhead at the anchor point or riser pipe at opposite end	Static Strength exceeds pipe	
Flexible Joint	A	Provide adequate angular rotation to minimize riser pipe bending stress. Withstand operational temperatures	Fully support riser under full section shearing of elastomer/metal shim matrix	Manufacturer's Specifications
External Tieback Connector	A	Lock and unlock via ROV or umbilical actuation. Generate preload and maintain sealability up to extreme load cases. Unlock force greater than locking force. Secondary Unlocking capability	Static Strength exceeds pipe or stress joint. Internal pressure loss before exceeding allowable stress	API TR 17TR7
Internal Tieback Connector	A	Lock and unlock with vertical load and/or rotation. Generate preload and maintain sealability up to extreme load cases.	Static Strength exceeds pipe. Internal pressure loss before exceeding allowable stress Minimize passive actuation design	API TR 17TR7
J-lay Collars	A	Provide means to hold a SCR during J-lay installation	Static strength exceeds pipe	API RP 2RD, API Spec 6A
Buoyancy Modules	C	Reduce riser wet weight or provide positive lift forces to form designed riser configuration (e.g., for a lazy wave riser shape)	End of life buoyancy force adequately preserved per the system design	API Spec 17L1 API RP 17L2 API Spec 16F
Strakes	C	Reduce VIV fatigue damage ROV-installable (optional)	Covered length should consider potential loss or ineffectiveness of some percentage of strakes over time (e.g., due to damage or marine growth)	API Spec 17L1 API RP 17L2
Fairings	C	Reduce VIV fatigue damage Weather-vane with current direction to minimize drag load ROV-installable (optional)	Covered length should consider potential loss or ineffectiveness of fairings over time (e.g., due to damage or marine growth)	API Spec 17L1 API RP 17L2
Other Ancillary Equipment	C	To be prescribed in the riser design basis	To be prescribed in the riser design basis	API Spec 17L1 API RP 17L2

Table 11 defines three categories of components based on type of loading. The allowable stresses for each category should be per the identified subsection of this Recommended Practice, as well as any other relevant standards identified in Table 10.

Table 11 — Riser Component Design Categories

Category	Type of Loading	Design Requirements
A	Primary load path and/or pressure containing	For Operating/SLS and Extreme/ULS, use WSD (subsection 5.4) For Survival/ALS, use LSD (subsection 5.5)

B	Primary load path and/or pressure containing with redundancy	WSD (5.4 and 6.2)
C	Not primary load path or pressure containing	Per relevant standards (e.g., Table 10)

In addition to the allowable working stresses referenced in Table 11, component design shall also account for the following allowable shear stresses in Table 12 as applicable.

Table 12 — Allowable Shear Stresses for Components

Load Condition	Case Design Factor F_D	Allowable Stress
		Shear
Operating / SLS	0.67	$0.6 \times F_D \times \sigma_y$
Extreme / ULS	0.8	$0.6 \times F_D \times \sigma_y$
Test (Shop) / TLS	0.9	$0.533 \times F_D \times \sigma_y$
Survival / ALS	1.0	$0.577 \times F_D \times \sigma_y$

Allowable bearing stresses shall be documented by the manufacturer. Bearing stresses shall not allow deformation to the extent that it compromises the structural integrity of the design.

Refer to Annex A for additional discussion on design safeguards and identification of critical areas for design verification, as well as the design of flexible joints, riser support structures, tensioner systems, and tie-back connectors.

6.2 Fatigue

6.2.1 Overview

Riser component fatigue assessment can be performed using several different approaches. Two common approaches are summarized in Table 13 and described below.

Other similar approaches that utilize the relationship between applied load and component principal stress can be used where appropriate.

Table 13 — Riser Component Fatigue Analysis Methods

Approach	Global Riser analysis	Component Analysis
Stress Amplification Factor (SAF)	Determines maximum allowable SAF based on SN curve and desired fatigue life.	Determines maximum component SAF and compares to maximum allowable SAF from global riser analysis
Interface Load Histogram	Outputs Load histograms at key component interface locations	Determines component fatigue life at critical locations

6.2.2 Stress Amplification Factor (SAF) Approach

The first approach utilizes a comparison of the maximum allowable stress amplification factor (SAF) calculated from the riser global fatigue analysis based on a desired fatigue life to the SAF calculated from 2D or 3D component local analysis.

The stress amplification factor is defined as the following:

$$SAF = \frac{\Delta S1}{\left(\frac{LC\ range}{Reference\ Section}\right)} \tag{38}$$

Where:

ΔS1 = maximum alternating tangential surface stress in which a crack can initiate based on LC range (stress)

LC range = Load case range (force)

Reference Section = Pipe area for 2D models and section modulus for 3D models

The assessed fatigue location (elevation) in the global model shall be the same as the component location. For the different reference pipe areas from the global and component analysis, the SAF shall be linearly adjusted for the same reference pipe area before the comparison. In the component analysis, the SAF should consider the stress amplification due to the geometrical discontinuity and pipe misalignment. If the maximum SAF from the component analysis is less than the maximum allowable SAF from the global fatigue, the fatigue life at this location meets the fatigue design requirements. For this reason, components in the primary load path should have features with smooth transitions and have adequately preloaded connections to improve fatigue performance.

Evaluation of the SAF during component analysis should be conducted below and above the separation point for preloaded components, as there is typically a change in SAF as the load path changes within connections when the preload is relieved. When SAF values are used, the component analysis does not produce an actual fatigue life but will provide a value that can be related to the global riser analysis as long as the reference sections are the same. In this approach, global analysis performs structural analysis and uses the S-N curve method to output an allowable SAF based on a desired fatigue life.

6.2.3 Interface Load Histogram Approach

Another method of assessing component fatigue involves performing a global analysis of the complete riser system, and then extracting load histograms at component interface locations to be used as input to a more detailed component analysis to calculate fatigue life at local hot spots using S-N methods (see Section 5).

The model used in the global analysis should include sufficient detail of the component geometry to ensure accurate and reliable interface load histograms are generated. The models used for component analysis should be much more detailed to ensure stress gradients and hot spots are adequately captured.

6.3 Manufacturing and Quality Control

A riser component or an assembly of riser components is considered a product. A complete riser system, a riser tensioning system, threaded and coupled casing, and a riser flange are all examples of riser products.

Requirements for product realization, including verification and validation, shall be per API Spec Q1. Requirements related to the product in API Spec Q1 shall include the following:

a) component loads from the riser analyses (see Section 4);

b) verification (see Section 5);

c) material and welding requirements (see Section 7).

Documentation required by API Spec Q1 shall be made available for review.

Use of existing designs qualified for more stringent service conditions than the project requirements can be used without conducting qualification review or testing. Where project service conditions are more stringent, supplemental verification, validation, and testing may be warranted to validate that the existing product satisfied the more stringent conditions.

NOTE HAZOP and FMEA are useful tools to ensure that important requirements are not missed. They also provide guidance for mitigation of risk.

7 Materials

7.1 Scope

This section provides requirements and guidelines for material selection, manufacture, testing, corrosion protection, fabrication, inspection and documentation.

7.2 General Requirements

7.2.1 Selection

Materials shall be selected to the following:

a) have properties necessary to comply with the functional requirements and be compatible with all anticipated internal fluids, external fluids, temperatures, and environments during all operations, consistent with design;

b) be suitable for all anticipated operations and loads associated with dynamic risers for floating production systems;

c) have the mechanical properties, including strength, toughness, fatigue performance, and chemical composition necessary to comply with design requirements;

d) be suitable for the intended fabrication and installation methods, such as welding, induction bending, cladding, reeling, corrosion protection, etc., as necessary;

e) avoid a risk of galvanic corrosion and dissimilar material interaction issues;

f) retain adequate material performance during the entire anticipated life of the riser;

g) have sufficient resistance to abrasion/wear, erosion, or mechanical damage likely to occur during all anticipated operations.

Manufacturing processes should be selected such that critical areas of risers and riser components can be appropriately inspected and non-destructively examined (NDE).

Pressure containing components and components directly welded to pressure containing components shall not be metal castings.

Galling should be considered as part of material selection for components with high sliding contact stresses, such as threaded connections.

Non-metallic material selection (i.e., polymers, elastomers, composites, etc.) shall be based on an evaluation of the compatibility of the non-metallic material with service environment, including temperature, cyclic loading and composition of anticipated fluids and substances to which the material can be exposed.

Each of the following should be considered as appropriate to non-metallic seal requirements and evaluated when selecting the material:

— adequate physical and mechanical properties, such as hardness, strength, elongation, elasticity, flexibility, compression set, tear resistance, etc., during all anticipated operations;

— resistance to high-pressure extrusion or creep;

— resistance to thermal cycling and dynamic loadings;

— resistance to issues associated with rapid gas decompression;

— resistance to degradation of properties during design life.

7.2.2 Specifications

Materials shall comply with the requirements of recognized industry standards. A list of acceptable standards are provided Table 14. Alternate industry recognized standards may be used where the use is supported with technical justification.

Table 14 — Applicable Material Specifications

Item	Standards
Line pipe	API Spec 5L, API Spec 5CT
Welding	ASME Section IX, API Std 1104
Components	API Spec 2SF, API Spec 6A, API Spec 20B, API Spec 20C, API Spec 20E, API Spec 20F, DNV-RP-0034, or applicable ASME standards
Flexible pipe	API Spec 17J, API Spec 17K, API RP 17B
Composite Pipe	DNV-ST-F119

Component specifications shall be prepared for all riser components. These component specifications should establish requirements for method and process of manufacture, chemical composition, heat treatment, physical and mechanical properties, weldability, dimensions and tolerances, surface conditions, testing, examination and NDE, marking, temporary coating and protection, certification, and documentation.

Manufacturing procedure specifications (MPS) shall be prepared by the manufacturer for manufacture and fabrication of all riser components. The MPS should describe how the specified properties are to be achieved and verified as part of manufacturing and fabrication. The MPS should address all factors that affect the quality and reliability of the manufacture or fabrication. Every principal manufacturing or fabrication step from receiving material to shipment of finished product(s) should be addressed, including heat treatments, forming, and machining operations, examinations, NDE and checkpoints. References to the detailed procedures used for the execution of all steps should be included.

Specifications related to welding such as welding procedure specifications (WPS) and associated procedures shall be prepared for all welded components ensuring that the properties required by the design are satisfied.

7.2.3 Qualification of Materials and Manufacturers

All materials used for risers and riser components shall be qualified as per specification. The qualification should address potential failure modes, including factors associated with all anticipated internal and external fluids, temperatures, loads and cyclic loads, installation methods, adjacent materials and design lifetime. If qualification of materials by testing is required, the extent of testing and associated analyses and acceptance criteria should be documented.

The complexity and criticality of the product to be manufactured or fabricated and the experience of the manufacturer or fabricator should be taken into account as part of the riser design process.

For strain-based design, both material and welding procedures shall be selected and qualified for required strain capacity.

For fatigue critical components or weldments, both material and welding procedures shall be qualified for the required fatigue capacity.

7.2.4 Traceability

All pressure containing and load bearing components and materials, including fasteners, shall be traceable, including stages of manufacture, fabrication, transportation and handling. Less critical components should also be traceable.

7.2.5 Marking

Materials and components should be marked in accordance with the requirements of the applicable product standard or operator's requirement. All marking should be such that it is easily identifiable and retained during subsequent activities. Marking should not compromise product performance. For example, marking by die stamping should not be allowed in fatigue sensitive areas.

7.2.6 Inspection Documents

Components should be supplied with an inspection document in accordance with applicable product standard or owner's requirements.

7.2.7 Records

Complete records according to operator's specifications should be provided. These records can include chemical composition, material properties, fabrication procedures, dimensions, inspection, welding procedures, handling, transportation, storage, and installation.

7.2.8 Protection and Handling

Pipe and other components should be protected and handled in accordance with the requirements of the applicable product standard or operator's requirement. For example, pipe/connector ends and other component openings can be fitted with suitable end caps/covers.

Surface condition for pipe and other components should be controlled during all phases of manufacturing, storage, transportation and installation to minimize initial defects that might impair fatigue performance. These include, handling damage, corrosion, surface roughness and grinding.

7.3 Steel

7.3.1 General

Steel should be manufactured in a manner ensuring uniform chemical composition, uniform material properties and fine grain structure.

Steel should be manufactured by a process that includes vacuum degassing or AOD.

Unless otherwise justified, all steel line pipe used in riser systems shall be PSL2 per API Spec 5L.

7.3.2 Material Test Locations for Forgings / Induction Bends

Material test locations for forgings and induction bends shall be in accordance with ASME B16.49. Refer to Section 7.10.1 for more information on forgings.

7.4 Other Materials

7.4.1 General

Other materials, such as titanium or composites, may be used in compliance with recognized industry standards for offshore oil and gas applications.

7.4.2 Titanium

Titanium engineering, manufacturing and handling procedures are distinct from carbon steel and appropriate methods and procedures shall be adopted to ensure titanium integrity is not compromised.

In accordance with ASTM B381, there are primarily two grades of titanium suitable for offshore riser use:

- ASTM Grade 23 Titanium: (UNS R56407) Nominally Ti-6%Al-4%V ELI (extra-low interstitial, 0.13% max. O)
- ASTM Grade 29 Titanium: (UNS R56404) Nominally Ti-6%Al-4%V-0.1%Ru ELI (extra-low interstitial, 0.13% max. O)

Grade 29 titanium is selected for sour service where the NACE standard is required, and/or when riser service temperatures are expected to exceed 80C, the crevice corrosion threshold temperatures for the Grade 23 alloy. Grade 23 represents the most economic alloy choice for service temperatures below these limits, and where NACE compliance for sour service is not required.

Titanium is corrosion resistant by means of a tenacious and protective natural oxide layer resulting from its reactive metallurgy. By itself, titanium would remain virtually corrosion free for far longer than the service life of a subsea riser. Two important considerations when deploying titanium stress joints into a subsea riser system are the riser's cathodic protection system and galvanic coupling of dissimilar metals. Although internal riser surfaces are not exposed to CP system charging concerns, galvanic effects arising from dissimilar metal contact still need to be considered. If produced well fluids allow the selection of carbon steel, direct galvanic coupling of titanium to the steel generally does not present a compatibility concern. If produced well fluids require the selection of corrosion resistant alloys (CRAs), either as overlays or solid pipe, then there are no compatibility issues. This compatibility stems from the similarity in corrosion potential of passive Fe-Ni-Cr-Mo and Ni-Cr-Mo alloys to those of titanium alloys in these fluids. Titanium in direct contact with carbon steel shall be designed with sufficient buffer, shielding, and isolation technologies to mitigate galvanic dissimilarities.

Titanium is highly corrosion resistant to seawater and produced well fluids such as hydrocarbons, NaCl brines, organic acids, CO2, H2S, elemental sulfur and liquid mercury. However, additional precautions should be employed when injecting hydrochloric (HCL) acid, hydrofluoric acid (HF) and methanol (MeOH) containing solutions. Commercial inhibitor systems developed to protect steel do not protect titanium although there are commercial inhibitors available which were developed specifically for titanium which work well in combination with the steel inhibitors. Titanium shall not be exposed to pure methanol; approximately 10% water cut is recommended.

Where titanium is used for stress joints, it is important to apply a mean stress correction, where the R-ratio can vary from 0.7 down to -1.0 as the wall thickness increases and bending becomes more dominant over tension in the cyclic stress field.

7.4.3 Composites

Composite materials have failure modes significantly different from metals and where used in riser systems, appropriate design, testing, qualification and handling methods should be followed. The design and engineering of composite pipe and components is outside the scope of this standard.

7.5 Requirements for Elevated Temperature

A material should only be used within the range of temperatures for which the strength properties are defined in the product standard. If the product standard does not contain the specific strength values for the maximum design temperature, strength properties should be determined by tensile testing at the maximum design temperature.

As part of riser design, the appropriate strength de-rating at elevated design temperature shall be included in the component strength assessments. For risers that are an extension of a pipeline or subsea flowline, the strength de-rating methodology should be consistent with the corresponding de-rating of the connecting pipeline or flowline.

7.6 Requirements for Sour / Acid Flowback Service

Metallic materials in sour production environments or exposed to acid flow-back conditions shall comply with NACE MR0175/ISO 15156 (all parts)

Qualification testing of all riser pipe, other riser components, welding consumables and coatings, as applicable, shall be carried out in accordance with NACE MR0175/ISO 15156 (all parts).

Potential degradation of fatigue performance in sour production or acid flow-back environments shall be considered.

Drying or use of scavengers or corrosion inhibitors shall not relax the requirement for sour production equipment to meet NACE MR0175/ISO 15156 (all parts). Risk for sour conditions during the lifetime should be evaluated, especially if water injection is foreseen.

7.7 Requirements for Applications where Strain Exceeds 0.5%

If the total nominal strain in any direction (excluding strain concentration) due to installation and operations exceeds 0.5 % at the OD surface, the following additional requirements should apply.

a) Material selection—Tensile property specifications for base materials used in strain-based design should include upper and lower limits for longitudinal yield strength, uniform elongation, and yield-to-tensile strength ratio. Tensile, Charpy impact, and fracture toughness (CTOD) testing should include the direction associated with the largest strain, e.g., the longitudinal direction for pipe. Tensile testing results should be documented and include a significant portion of the stress-strain curve. Charpy testing should be done on material in the appropriately strain-aged condition. Fracture toughness testing shall be performed for both the as-welded (CTOD) and strain and aged conditions (J-R Curve). For applications in which the material is subjected to coating (e.g., application of fusion bonded epoxy), mechanical properties in the as-coated condition should also be assessed.

b) Tests should be performed to demonstrate that the riser welds have the necessary resistance against both crack extension by tearing and unstable fracture due to both installation and in-service

conditions and temperatures. Assessment shall be in accordance with the reeling requirements of DNV-ST-F101 and DNV-RP-F108.

NOTE Internal pressure can reduce the longitudinal strain capacity by more than 50 % and should be considered in the design and qualification.

7.8 Prevention of Brittle Fracture

7.8.1 General

Materials shall be selected to prevent brittle fracture. Charpy impact testing shall be performed in accordance with component specifications to verify material and weld toughness in the final delivery condition. The test temperature for Charpy impact testing of steel pipes should be in accordance with Table 15.

Table 15 — Test Temperature for Charpy Impact Testing of Steel and Steel Welds

Nominal Wall Thickness mm	**Test Temperature Relative to T_{min}** °C
≤ 20	T_{min}
20 < t ≤ 40	T_{min} – 10
>40	T_{min} – 20
NOTE T_{min} refers to the lowest anticipated service temperature.	

7.8.2 Fracture Mechanics Toughness Testing

For all pressure-containing components thicker than 13 mm, all structural components identified as fracture or fatigue critical or when specified, fracture mechanics toughness testing of the base metal and welds should be performed in accordance with industry standards such as ISO 12135 or ASTM E1820.

For steels, base metal, heat-affected zone and weld-metal, the minimum toughness should be specified in project requirements.

For pipe and forging base materials to be welded for fracture or fatigue critical components, fracture mechanics testing should be done on material representative of the weldment, with due consideration for hot-working ratio, wall thickness and heat treatment. A minimum of 3 fracture mechanics test samples should be tested from a pertinent orientation, such as L-S, per ASTM E1823, for pipe girth welds. The minimum acceptable value (minimum of three or equivalent) should be 0.25mm CTOD.

For weldments, fracture mechanics testing shall be conducted for both weld metal and HAZ. For both, a minimum of three fracture mechanics test samples should be tested from a pertinent orientation. The minimum acceptable value (minimum of three or equivalent) should be 0.25mm (CTOD). For reeled applications, testing shall characterize fracture toughness for all reeling cycles, including development of J-R curves.

In situations where pipe will be reeled during installation, fracture toughness samples shall have received a strain history representing the full installation process including contingency cycles. Full scale sample straining (bent as a complete pipe correctly simulating the strain variation through the pipe wall) are

recommended, as compared to test specimens taken from small scale straining where the strain is purely axial.

NOTE Environmental conditions should be considered when specifying fracture mechanics toughness testing.

7.8.3 Hardness

Hardness of base material and weld cross-section samples shall be tested using the Vickers HV10 method according to ASTM E384. Hardness readings shall satisfy the requirements of the welding specifications.

Hardness test locations for seamless and seam-welded pipe shall be as shown in Figure 1, except that,

— when $t < 4.0$ mm, it is only necessary to carry out the mid-thickness traverse,

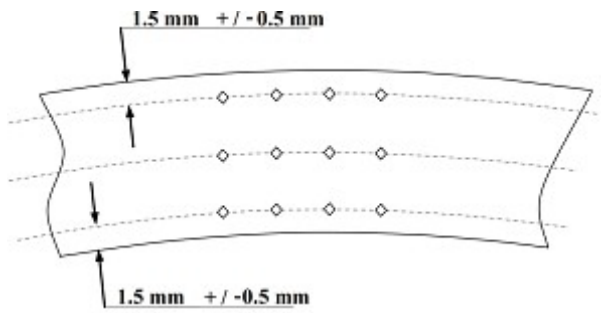
— for pipe with 4.0 mm $\leq t <$ 6.0 mm, it is only necessary to carry out the inside and outside surface traverses.

Hardness testing of welds shall be performed on the specimens used for macro examination, and as shown in Figure 1 and Figure 2.

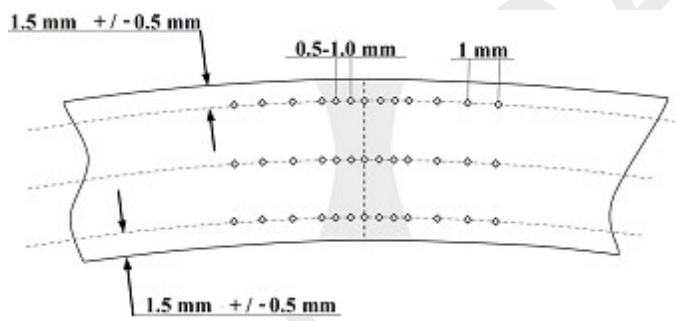
In the weld metal of seam welds, a minimum of three indentations equally spaced along each traverse shall be made. For girth welds and seam welds, indentations in the HAZ shall be made along the traverses for each 0.5 mm to 1.0 mm (as close as possible but provided indentation is made into unaffected material, and starting as close to the fusion line as possible according to Figure 1).

Hardness testing of clad or lined pipes shall have an additional hardness traverse located in the middle of the CRA material (see Figure 2).

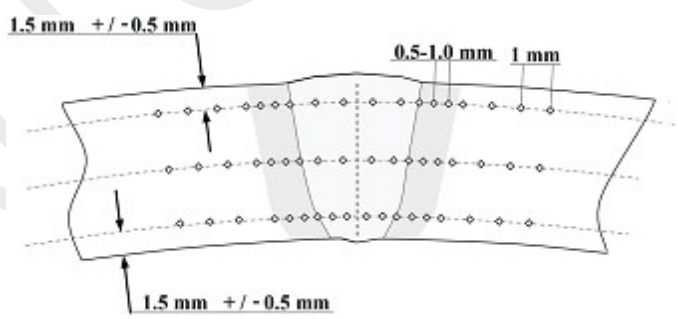
For hardness testing of weld overlay, testing shall be performed at a minimum of three test locations: in the base material, in the HAZ and in each layer of overlay up to a maximum of two layers.



a) Seamless Pipe



b) Seam-welded Pipe Without Consumables



c) Seam-welded Pipe with Consumables

Figure 1 — Hardness Locations in Seamless and Seam Welded Pipe

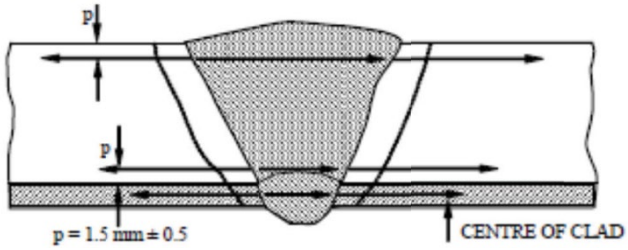


Figure 2 — Hardness Locations for Clad Materials

7.9 Corrosion Mitigation

All riser system components should be made of materials appropriate for the anticipated service condition or have appropriate corrosion protection to avoid damage involving external and internal corrosion. Internal corrosion protection can be provided by a combination of material selection and corrosion inhibition. External corrosion protection can be provided by a combination of coatings, cathodic protection. As a minimum, the following should be considered: marine environment, all anticipated internal environments (including production, hydrotest fluids, well stimulation, etc., as applicable), potential galvanic properties of welds and attached components, crevice corrosion, cathodic protection (CP), and splash zone requirements.

For risers manufactured from carbon or low alloy steel, corrosion allowance requirements should be assessed and incorporated into design calculations.

For CP, the riser design should ensure reliable electrical continuity or isolation as applicable to each component for the design life. The CP system should be designed and coordinated with that of other adjacent equipment, such as the hull of the floating installation itself, other risers and subsea equipment.

The design of the CP systems should meet the minimum requirements in ISO 15589-2 or equivalent.

If materials susceptible to hydrogen embrittlement are used with CP, qualified mitigations (such as coatings and weld procedures) should be taken to avoid possible failure mechanisms. Materials of concern can include high strength steel, duplex stainless steel, and butter welds.

7.10 Products

7.10.1 Forgings and Extrusions

7.10.1.1 General

The following general requirements for forgings and extrusions apply.

a) Fabrication should be in accordance with the requirements of an industry recognized specification including API Spec 2SF, API Spec 6A, API Spec 20B, API Spec 20C, DNV-RP-0034 or other recognized equivalent.

b) Steel forging shall be performed in compliance with the accepted MPS. Each forged product shall be hot worked as far as practicable, to the final size with a minimum reduction ratio of 4:1.

c) The work piece shall be heated in a furnace to the required working temperature.

d) The working temperature and soak time shall be monitored during the forging process.

e) If the temperature falls below the working temperature, the work piece shall be returned to the furnace and re-heated before resuming forging.

f) The identity and traceability of each work piece shall be maintained during the forging process.

g) Weld repair of forgings shall be allowed only if all of the following are met:

— agreement between the manufacture and purchaser;

— a specific and qualified weld procedure is developed for the repair;

— the forging fatigue life is re-evaluated as fit-for-service with the repair weld (i.e., weld versus base metal S-N curves).

7.10.1.2 Testing

Destructive testing shall be performed according to the component specification. A full-thickness prolongation representative of the thickest section of a production forging or extrusion should be used, or an extra forging should be sacrificed. The extent of testing to be performed during production should be as per product specification. Testing can include chemical composition, tensile, Charpy impact, fracture toughness, hardness, and metallography.

7.10.2 Bolting

Carbon and low-alloy steel bolts and nuts for pressure-containing and main structural applications shall be selected in accordance with API 20E and API Spec 17D. Riser bolting in the primary load path shall be classified as “Critical” bolting per API Spec 17D.

When bolts and nuts are to be used at elevated temperature, the need for strength de-rating shall be considered.

UNS N06625 (Alloy 625) in accordance with ASTM F467 is applicable as subsea bolting material without CP but should only be used in the solution annealed or annealed condition (ASTM B446) or cold-worked to SMYS 550 MPa maximum, unless exposure to CP can be excluded. Restrictions for sour service according to NACE MR0175/ISO 15156 (all parts) shall apply when applicable.

Maximum hardness shall be limited to 35 HRC for solution annealed or cold-worked type AISI 316 austenitic stainless steel, in accordance with ASTM A240, and any other cold-worked austenitic alloys. Precipitation hardening Fe-base or Ni-base alloys, duplex and martensitic stainless steels should not be specified as bolting material if subject to cathodic protection.

7.10.3 Syntactic Foam Buoyancy

Buoyancy materials should be rated to the required water depth and provide the required buoyant lift over the intended design life.

Syntactic foam exhibits a progressive buoyancy loss due to water absorption over time. The rate of buoyancy loss is inversely related to the strength and density of the syntactic foam. Typically, heavier or stronger syntactic foam materials are required for service at greater depths and over longer periods in service. Selection of a syntactic foam product should be based on test data.

Refer to Section 6 for design of buoyancy modules.

7.10.4 Coatings

7.10.4.1 Coating Selection

External coating selection, including field-joint coating, shall take into account the following:

— tensile strength, elongation, flexibility, adhesion, resistance to disbanding, abrasion and impact resistance;

— compatibility with temperature and pressure requirements;

— thermal insulation requirements;

— compatibility with environmental and biofouling requirements;

— ease of repair, resistance to mechanical damage and compatibility with the cathodic protection systems.

NOTE For guidance on preparation of manufacturing specifications, testing and acceptance criteria for coating systems refer to DNV-RP-F106 [S24].

7.10.4.2 Insulation Coating Systems

Insulation systems can be required to improve flow assurance. Component specifications shall indicate if insulation is required and the necessary thermal and mechanical properties considering the following.

a) Whether directly applied to the surface, pipe-in-pipe or active heating;

b) The effect of compression, creep, densification and water adsorption on selected thickness;

c) The effect of internal temperature on the integrity of the insulation interacting with seawater (hydrolysis).

d) Qualification testing with emphasis on cathodic dis-bondment, simulated service tests, bend tests, adhesion tests, shear/compressive strength and the U value determination;

e) Method of installation, i.e., S-lay, J-lay, or reeled. The following should be considered in the selection process:

   — lay tension capabilities of each vessel;

   — sag and overbend stresses;

   — reeling of large diameter pipelines (plasticity and ovalization);

   — field joints (complexity of field joints and application times);

   — annulus gap between inner and outer pipe (pipe-in-pipe);

   — protection of insulation in the annulus gap for pipe-in-pipe during welding of the outer pipe.

7.11 Manufacture, Welding, and Fabrication

7.11.1 General

The manufacturer should implement a system covering all aspects of the welding specification and quality control involving competent personnel with defined responsibilities; see API Spec Q1.

Material traceability should be maintained during all stages of manufacturing and fabrication.

Dimensional tolerances and surface roughness during manufacture and fabrication should comply with those assumed in the design analysis of the riser system.

All defects and deficiencies should be corrected before structural components are painted, coated or otherwise made inaccessible.

The fabricator should establish and use a consistent weld numbering/identification system for systematic weld identification on all relevant drawings and as reference in all documentation.

7.11.2 Welding Procedure Specifications

Welding procedure specifications should be established in accordance with API Std 1104, ASME BPVC Section IX, or equivalent codes.

7.11.3 Qualification of Welding Procedures

Welding procedures for steel should be qualified in accordance with API Std 1104, ASME BPVC Section IX, or equivalent codes.

Mechanical testing should be performed as specified in API Std 1104, ASME BPVC Section IX, or equivalent codes and the additional requirements defined in 7.8.

The test weld should be 100 % examined for both surface and volumetric defects with the relevant NDE methods after all welding and grinding is completed.

NDE of qualification welds should not be performed until at least 24 hours have elapsed since the completion of welding. This time delay may be reduced subject to agreement, provided that welding processes with low content of hydrogen are used, adequate handling of welding consumables is verified and measures such as post-heating of the weldments are taken to control hydrogen content.

7.11.4 Fatigue Performance of Girth Welds

Welding procedure specification and qualification shall produce girth welds whose fatigue performance meets or exceeds the S-N fatigue curve selected for design. The SN curves used shall be based on an industry recognized curve (refer to BS 7608 or DNV-RP-C203) or a new curve qualified according to the procedure defined in DNV-RP-C203.

Proposed welding procedure performance shall be demonstrated by either fatigue testing of small-scale strip tests or by full-scale fatigue testing. This requirement may be waived if the welding procedure has been previously qualified for fatigue performance, is fully documented, and is accepted by the operator as demonstrating equivalent performance for the intended service.

NOTE 1 Fatigue test data should demonstrate the intended S-N fatigue performance based on a minimum 95 % confidence interval and taking into account the number of samples in the test population.

NOTE 2 The mean S-N curve should exceed the design curve by at least two (2) standard deviations.

If a novel welding procedure is selected, the fatigue performance should be qualified. The number of test specimens should be adequate to derive the mean and design S-N curve with a minimum 95 % confidence.

Specimen quality for fatigue testing should be representative of that expected to be attained under actual production welding. All fatigue test specimens should be inspected by NDE to the same requirements as specified for the production welds and meet the same NDE acceptance criteria established prior to being tested. For girth welds of risers subject to >0.5 % nominal strain in any direction during installation or in-service conditions, fatigue testing should be carried out after application of representative cycles of straining.

For girth welds designed to operate in a H_2S and/or CO_2 environment, fatigue curves should be modified to address the environmental effect.

7.11.5 Strength Requirements for Strain-based Design

For strain-based design, overmatching the strength of welds relative to base material is important. Maximum specified yield strength of the base material should be less than the yield strength of the weld metal after straining. Weld metal should be batch tested to determine all weld metal yield and tensile strengths.

7.11.6 Material Receipt, Identification and Tracking

All material should be inspected for damage upon arrival. Quantities and identification of the material should be verified and preserved during handling, storage and all fabrication activities. Damaged items should be clearly marked and disposed of properly.

Items should be inspected for loose material, debris and other contamination and cleaned internally before being added to the assembly. The cleaning method should not cause damage to any internal coating.

A tracking system should be used to maintain records of the various components and welds.

7.11.7 Cutting

Local effects on material properties and carbon contamination by thermal cutting should be controlled. Preheating of the area to be cut can be required. Carbon contamination of the affected area should be removed.

7.11.8 Forming of Materials

Forming of plates, pipes, etc. should be carried out according to a specification outlining the successive and controlling steps. The forming specification should be qualified by destructively testing a qualification sample. Essential variables for the qualification test should be established and should include heating and heat treatment temperatures and total strain. The effects of strain aging should be addressed.

The specified mechanical properties should be attained in the final condition of all components.

7.11.9 Properties After Forming and Heat Treatments

For materials subjected to heat treatment, hot or cold forming, welding, coating involving high temperatures or other processes that can affect the material properties, compliance with the specified requirements in the final condition should be documented. Documentation should be provided for parent material and, in case of welded components, for weld metal and heat-affected zones.

Suitable allowances for possible degradation of the mechanical properties of a material, e.g., as a result of subsequent fabrication activities, should be addressed in the specification.

7.11.10 Welding Preparation and Fit-up

Mill scale, rust, etc. should be cleaned from the weld bevel area prior to welding, and the groove should be dry and clean. The fit-up should be checked before welding. The root gap and root high-low should be measured and recorded to demonstrate conformance with the welding specification.

Pipe and components should be supported in such a way that excessive stressing of the welds due to shrinkage during welding is avoided.

Radial offsets and out-of-squareness of pipe abutting ends should be minimized, for example by rotating the pipe until the best possible fit has been obtained.

Dimensional requirements at pipe ends and fit-up tolerances for fatigue-sensitive locations should be consistent with design requirements.

Welding of titanium shall not be performed in the same room/place where carbon steel welding is performed in order to prevent carbon contamination of titanium welds.

7.11.11 Cladding

Cladding is a material of dissimilar chemical composition metallurgically bonded to a structural material surface for improved corrosion protection and/or wear resistance. Cladding in this section refers to the metallurgical bond of corrosion resistant alloy (CRA) to the substrate for corrosion protection. This also refers to clad ends of mechanically lined pipe. Clad welds are girth welds of two pipes with internal cladding.

Clad line pipe should be in accordance with API Spec 5LC or other recognized industry standard.

The properties of the clad material and clad-steel interface should be qualified for the intended service.

The additional wall thickness caused by cladding may be used in strength calculations only if it is of similar strength to the substrate, permitted by industry guidelines or qualified by appropriate testing and/or conservative finite element analyses. The weight and the stiffness from the clad layer must be considered in the design calculations.

The effective depth of cladding is the depth to which the specified chemical composition is achieved below the final surface finish (e.g., as welded, after machining, etc). Chemical samples should be removed below the specified minimum effective depth during qualification to verify the chemical composition is adequate for corrosion protection.

Welding consumables should have less than 5 mL/100 g of diffusible hydrogen with proper storage techniques. Welding consumables should conform to AWS A5.14/A5.14M for CRA consumables and include a materials test report (MTR). The maximum hardness for both the surface of the cladding and the interface with carbon steel pipe should be in accordance with NACE MR0175/ISO 15156 (all parts) for

non-sour or sour service. Visual inspection and either magnetic particle or dye penetrant testing should be done after the overlay procedure. All surface breaking flaws should be removed.

During tacking and girth welding of clad pipe, the oxygen content of the backing gas should be measured and controlled to be less than 500 ppm until the weld thickness is a minimum of 10 mm. Welding consumables should conform to AWS A5.14/A5.14M for CRA consumables and include a MTR. The MTR should provide the actual mechanical testing results for each lot of the consumables. A procedure should be developed for handling, storing, and identifying welding consumables.

The maximum hardness of the clad welds should be in accordance with NACE MR0175/ISO 15156 (all parts) for sour service.

CRA bends should be qualified to ISO 15590-1. Corrosion testing should be performed on bends with the surface in the as finished condition for production (e.g., ASTM G48 for duplex and nickel alloys). If a gauging tool is used to check the ID dimensions of a pipe, the gauge should not be fabricated with iron-based materials to prevent contamination of the corrosion resistant cladding. Acceptable materials are stainless steel or corrosion resistant material similar to the cladding.

7.11.12 Heat Treatment After Forming and Welding

Heat treatment should be performed in accordance with written manufacturing procedure specifications that describe the control of the parameters critical for the heat-treatment process. The heat treatment specification should be qualified by destructively testing qualification samples representative of the final product. The specified mechanical properties should be attained in the final condition of all components. Essential variables for the qualification test should be established and should include heating and heat treatment temperatures and total strain (e.g., for induction bending), as applicable. Essential variables and acceptable ranges for the essential variables should be agreed between manufacturer and purchaser.

7.12 Examination and Non-destructive Examination (NDE)

7.12.1 General

NDE should be chosen consistent with the method’s ability to detect and size applicable imperfections for the material, geometry and welding process used. As the NDE methods differ in their limitations and/or sensitivities, combinations of two or more methods may be required to ensure reliability.

The preferred method for detection of surface imperfections in ferromagnetic materials is magnetic particle inspection (MPI). The preferred method for detection of surface imperfections in non-magnetic materials is dye penetrant examination. MPI should use the wet fluorescent method consistent with existing standards, such as ISO 9934. The surface condition of the component being examined using MPI or dye penetrant should be sufficiently smooth to reliably detect flaws smaller than the associated acceptance criteria, as shown in the applicable component specification.

For detection of internal imperfections, either UT and/or radiographic examination should be used. It may be necessary to supplement radiographic testing with UT or vice versa to enhance the probability of detection or characterization/sizing of flaws.

UT examination should be used when it is necessary to know height and length of planar imperfections, e.g., to be consistent with fracture mechanics assessments.

Alternative methods or combinations of alternative methods for detection and sizing of imperfections may be used if it is demonstrated that they are capable of detecting and sizing imperfections with an acceptable equivalence to the preferred methods.

Detailed procedures for all visual examinations and NDE consistent with existing product standards and codes, as applicable, should be drafted.

Load bearing attachment welds onto the surface of a rolled product should be examined using UT for laminar tearing.

All NDE should be documented in such a way that the tested areas can be easily confirmed later.

7.12.2 Personnel Qualifications

All personnel involved in visual examination should be qualified and certified in accordance with recognized standards, consistent with relevant specifications.

7.12.3 Visual Examination and NDE of Welds

Completed welds should be subjected to visual examination and NDE during manufacture and fabrication. The following should be applicable to all welded joints.

a) Welded joints should be visually examined before other NDE is performed.

b) All girth welds in riser pipe and other tubular riser components should undergo 100 % volumetric (UT and/or radiographic, as applicable) examination.

c) For girth welds in fatigue sensitive service, UT examination should be considered to address potential for planar flaws in the weld root region.

d) NDE should be carried out on the weld in the final heat-treated condition.

e) All NDE and visual examination should be documented such that the examined areas can be easily identified and such that the performed testing can be reliably repeated. The reports should identify all indications present in the weld area and state, whether or not the weld satisfies the acceptance criteria.

f) AUT of clad welds should be qualified with the same CRA cladding and thickness as used during production. The AUT system should demonstrate the ability to detect and accurately size length and vertical height of indications with a resolution compatible with the applicable acceptance criteria using a qualified system. The AUT system should be calibrated throughout the production process. Defects in the ends of the CRA pipe should be accounted for to assist in determining if the flaw is located in the weld or in the ends.

g) Where there is concern of internal suck-back of clad pipe welds or other quality issues (oxidation, weld root reentrant angel, etc), internal inspection using a bore camera shall be performed.

7.12.4 Acceptance Criteria

Acceptance criteria for NDE methods should be established either from results of fracture mechanics analyses (fit for purpose approach, for AUT only) or from workmanship criteria (refer to 5.6.5) based on recognized industry standards, such as API Std 1104 acceptance criteria. The acceptance criteria should be adapted to the selected inspection systems and take into account their sizing accuracy and reliability.

8 Fabrication and Installation

8.1 General

8.1.1 Purpose

This section provides minimum requirements and general guidance for the fabrication and installation of marine riser systems. Fabrication and installation requirements and guidelines discussed in this section are primarily intended to address quality assurance and quality control (QA/QC) and installation practices that ensure riser systems are fabricated and installed in a safe manner and in compliance with the design and regulatory requirements. Guidelines for verifying that installed riser systems meet design requirements are also presented.

8.1.2 Scope

Fabrication refers to all machining, welding, coating, testing, QA/QC, and other activities required to manufacture a riser system.

Installation includes land transportation to an offshore marshalling site, marine transportation to the installation site, and marine installation operations.

8.2 Fabrication

8.2.1 QA/QC

Prior to commencing fabrication, a QA/QC plan shall be developed. The QA/QC plan shall:

— describe the quality system in accordance with a recognized industry standard;

— define procedures for processing non-conformances including root cause evaluation and corrective action;

— set forth the requirements for inspection and test plans (ITP).

Any occurrence of non-conformities shall be investigated to determine the root cause. Corrective action shall be taken to address the non-conformity and prevent further occurrences.

Each ITP shall include the following:

— breakdown of tasks;

— specification requirements;

— inspection intervals;

— third party inspection notification points.

The frequency and nature of inspection shall be sufficient to ensure the specified requirements are achieved.

8.2.2 Documentation

During fabrication, the following records shall be maintained as applicable:

— material certified mechanical test reports;

— dimensional logs;

— welding records;

— non-destructive examination (NDE) records;

— coating records;

— welder qualification records and inspection personnel qualification records;

— serialization/traceability records;

— hydrostatic test records;

— qualification test records;

— non-conformance reports.

These records shall be submitted to the operator as part of the fabrication documentation package.

8.3 Transportation, Shipping, and installation

8.3.1 Installation Analysis

8.3.1.1 Installation Load Cases

Installation and transportation load cases shall be identified for the proposed installation methods (see Section 4). Analysis shall be performed for these load cases as applicable.

8.3.1.2 Installation Limit Conditions

Installation and transportation analysis shall be performed to determine as applicable the maximum seastate or installation vessel motion, current profiles and wind profiles in which the required operations can be conducted while meeting strength and fatigue requirements as outlined in 8.3.1.3. Different limit conditions can be selected for various stages in the operation, depending on the duration of the installation operations and the consequences of exceeding the selected conditions.

8.3.1.3 Strength and Fatigue Evaluation

Strength analysis shall be conducted to verify that stress and strain levels remain within allowable limits throughout all of the transportation and installation operations. This strength analysis shall consider all loading conditions, e.g., lifting, reeling, towing, upending and stalking.

Depending on the type of riser and method of transportation, dynamic analysis shall be conducted to determine that the fatigue damage due to transportation and installation meets specification requirements. The risers shall be analyzed for installation conditions with varying amounts of riser deployed.

8.3.2 Risk Assessment

8.3.2.1 Risk Management Plan

A risk management plan shall be prepared to identify, describe, communicate and document the objectives, responsibilities and activities specified for assessing and reducing risk.

The plan shall reflect the criticality of the riser system, the criticality of planned operations, and previous experience with similar systems or operations.

Risks should be assessed against criteria for:

— personnel safety;

— environment;

— assets and/or lost production, and

— reputation.

Defined criteria shall comply with regulatory requirements, project policies and be specific for each of the areas above. The risk management plan shall ensure that risk assessments are reviewed and updated in accordance with the change management process.

It is the role of the risk assessment process to highlight critical activities and items such as:

— lifting and handling procedures;

— dropped objects/impact loads;

— snagging;

— simultaneous operations.

8.3.2.2 Risk Assessment Methodology

Risk assessment methodology shall follow industry-recognized processes such as quantitative risk analysis (QRA), failure mode and effect analysis (FMEA) or hazard and operability (HAZOP) assessment. These provide an estimation of the overall risk to human health and safety, environment and assets and shall consider:

— hazard identification;

— assessment of probabilities of failure events;

— consequence of failure;

— risk assessment.

8.3.3 Transportation and Handling Plan

A plan shall be developed for documenting procedures for safe and efficient packaging, transport and handling of the riser components, based on industry codes and recommended practices. This plan shall include:

— requirements for packaging to prevent handling damage;

— preservation requirements for short-term and long-term corrosion protection;

— requirements for the type of transport vehicle/vessel;

— consideration of transport vessel motions;

— deck loads and deck space requirements;

— lay down areas;

— weight, length and diameter of components to be shipped;

— location of lift points;

— recommended lifting and handling equipment;

— crane capacities and reaches at load, derrick capacities, and clearances;

— layout and method of securing riser components on the trucks, barges, supply boats, etc.;

— seafastening.

Transportation of line pipes by railroad shall meet the provisions of API 5L1. When line pipes are transported on barges and marine vessels provisions of API 5LW shall apply.

8.3.4 Installation Procedures

During installation the overall riser configuration shall be monitored for all relevant parameters. Typical parameters should include riser tension, departure angle, touchdown point and vessel heading. A risk assessment shall be conducted to evaluate a flooded riser scenario, including an evaluation of whether tensioners (if used) can hold on to a flooded riser and whether the abandonment and recovery (A&R) system is sized to safely lower a flooded riser.

In case of tensioner failure or failure in the tensioner system, the riser installation shall not re-start before the system has been repaired.

The A&R system shall be able to recover the riser when water-filled, or alternative methods for recovering the riser shall be available.

8.3.4.1 Installation Manual

Installation shall be according to a documented procedure; any deviation outside the established procedures shall be subject to a management of change process.

Procedures shall be supported by engineering calculations, qualification of personnel and processes, and qualification of equipment and installation vessels.

The installation contractor shall prepare an installation manual documenting all procedures required to meet the design requirements in a safe and efficient manner. The manual shall include the following:

— planned installation procedures, including TTR tubular and tensioner system installation;

— procedures and processes covering contingency situations;

— procedures for emergency conditions;

— limiting environmental conditions;

— weather window for completing operations;

— quality assurance activities such as inspection, witness/hold points;

— design and operational limitations;

— health, safety and environmental issues;

— responsibilities and communication procedures.

Contingency procedures shall consider the following, as applicable:

— weather conditions in excess of the installation limit conditions;

— ballast system breakdown or partial failure;

— loss of towing tension;

— excessive towing tension;

— third party marine activities;

— buckling and subsequent flooding of the riser;

— failure of vessel station keeping system;

— failure of tensioner system;

— loss of permanent or temporary buoyancy units;

— ROV breakdown;

— safe recovery of riser to reel;

— material sparing philosophy (permanent works and installation aids);

— other critical or emergency situations identified in FMEA analysis or HAZOP studies.

8.3.4.2 Towing

When towing is employed for riser installation, consideration shall be given to the following:

— interactions with third party marine activities during launch and tow;

— risk of riser damage during launch activities;

— tow distance and operating limit conditions with regard to weather window for the tow;

— towing speed and tension capacity of the tow vessel;

— fatigue damage of the riser due to interaction with the waves and current;

— control of weight and buoyancy distribution;

— ballast control during tow;

— ballast control during installation and upending;

— tow depth and hydrostatic collapse pressure of the riser;

— risk of interaction with the seabed and seabed objects including third party infrastructure;

— risk of buckling the riser pipe during upending.

Towing shall not commence unless an acceptable weather window for the tow is available.

Tension in the towing line and the towing depth shall be kept within the specified limits during the tow. Where required, ballasting or de-ballasting may be performed to adjust the towing depth to the specified values.

8.3.4.3 Reeling

SCRs installed using the reel-lay method may include both onshore and offshore welding. The following procedures shall be developed when reeling is used as the installation method:

— load-out/spooling of pipe onto reel;

— pipe straightening;

— installation of ancillary equipment, i.e., anodes, VIV suppression, instrumentation, etc.;

— recovery of pipe back to reel for contingency scenarios;

— installation, welding and NDE of sections requiring alternate installation methods, e.g., in-line structures;

— suitability of pipe insulation and field joint coatings (thickness and temperature dependency) for reeling process.

A riser that is reeled onto a spool can be subjected to large plastic strains. When two abutting pipe joints have dissimilar bending stiffness or strength, e.g., due to different wall thicknesses or varying material

properties, a discontinuity occurs. The result of this is a concentration of compressive strains in the softer joint in an area close to the weld.

8.3.4.4 S-lay or J-lay

The installation analyses and procedures shall accommodate the time and safe handling requirements for double/triple/quad/hex joints prior to assembly at the main line.

All coatings and ancillary equipment (strakes, buoyancy, etc.) shall be capable of withstanding loads due to passing over the stinger / through the roller box.

8.3.4.5 Stalking

TTRs are normally deployed from the floating production facility with a derrick and pipe-handling system. The tubular installation procedure determines the initial tubular tensions and the preload requirement between tubulars. Riser joint dimensions and weight limitations shall be considered in design of the pipe handling. Other riser types such as SCR's and FSHR's may be installed by stalking from a suitable installation vessel.

The following shall be considered in the installation of risers by stalking:

— special running and handling tools;

— space out requirements, where special segments can be used in the riser string to achieve a specific overall length between desired connection points;

— accessories that are attached to the riser during running, e.g., buoyancy modules, anodes, or VIV suppression devices;

— the method(s) used to guide the risers to the sea floor;

— interference with other risers, mooring lines and other obstructions during installation;

— motion compensation requirements that might be required during running and landing phases;

— support vessels, including ROVs that might be needed for deployment.

8.3.5 Installation Documentation and Verification

8.3.5.1 As-built Documentation

The as-built documentation shall be prepared after installation. The as-built documentation should include all applicable characteristic data identified in API RP 2RIM, including:

— summary of installation scope;

— key drawings of the riser system including extent, main interfaces, configuration, boundary conditions, main dimensions and main components;

— welding program details, including a weld map;

— mechanical connection make-up records;

— QA/QC program details, specifically including NDE records;

— incidents that occurred during installation;

— acceptance criteria and evaluation results;

— dimensional control adherence;

— as-installed surveys and drawings;

— confirmation of compliance with the design specifications and the approved fabrication plan including any approved deviation from the design specifications and the approved fabrication plan;

— pressure test records;

— as-built data book.

8.3.5.2 System Pressure Test

Riser systems that are considered part of a pipeline shall be pressure tested as per the requirements of API 1111.

8.3.5.3 TTR and Hybrid Riser Tension Setting

Riser tensions shall be verified upon completion of installation and monitored on a regular basis. Tension can be measured, for example, directly through load cells or strain gages or inferred indirectly by measuring pressure in tensioner cylinders or buoyancy can chamber gas volumes.

Tension monitoring (or installation) calculations should be submitted to the company for approval before actual installation takes place.

Deviations from the design specification shall be noted and as-built re-analysis conducted as deemed necessary.

8.3.5.4 SCR Configuration

Post installation survey for SCR's shall be required. This can include:

— touchdown point location (either directly or via inference from a work point);

— SCR lengths, lay azimuth;

— Location / depth of buoyancy modules/weight modules;

— VIV suppression coverage.

Deviations from the design specification shall be noted and as-built re-analysis conducted as deemed necessary.

8.3.5.5 Hybrid Riser Configuration

Post installation survey for hybrid risers shall be performed to verify the following, as applicable:

— tank depth and ballast system configuration;

— orientation and inclination;

— jumper configuration;

— riser base configuration;

— deviations from the design specification shall be noted and as-built re-analysis conducted as deemed necessary.

9 Riser Integrity Management

9.1 General

A riser integrity management (IM) plan shall be developed and implemented in accordance with API RP 2RIM. Riser integrity management is a continuous process applied throughout the life cycle to assure that the riser system is managed safely and cost-effectively, and remains reliable and available, with due focus on personnel, asset, operations and environment.

Riser integrity management includes the continuous evaluation of characteristic data, condition data, and operations data, as defined in API RP 2RIM, to ensure the riser remains fit for service throughout its service life.

Riser integrity management starts in design and a successful IM plan requires substantial characteristic data collected during design and construction, as described in API RP 2RIM. It also requires operations input throughout the design process to ensure the maintenance, inspection and monitoring requirements are consistent with design inputs and assumptions, as well as operating procedures and inspection and monitoring plans.

9.2 Re-assessment of Existing Risers

9.2.1 General

Re-assessment of risers should follow API RP 2RIM in the identification of triggers that require strength and/or fatigue analysis following the requirements in this Recommended Practice.

A re-assessment should reflect all relevant load cases (Section 4) from the original design and any previous re-assessments, taking into account changes in the condition of the riser over time (condition data) and operations data. Per API RP 2RIM, re-assessment does not necessarily imply complete re-analysis of all load cases if it can be demonstrated that load case results remain unchanged based on review of previous analyses. Load cases considered for re-assessment may be addressed on a case-by-case basis. Refer to Annex A for examples. Refer to API RP 2RIM for detailed guidance on re-assessment.

Alternative re-assessment methodologies, such as reliability-based assessments or use of operational or forensic data from analogous risers, may be considered where the provisions of this Recommended Practice do not adequately address specific circumstances in accordance with API RP 2RIM (refer to Annex A for further discussion).

Risers that have experienced anomalies (e.g., incidents, accidents, operating outside the design parameters) should be evaluated for change in their strength-resistance and fatigue-resistance capacities over time according to API RP 2RIM.

Risers originally designed to a different standard or code should be re-assessed in conformance with that standard or code.

9.2.2 Alternative Requirements for Survival/ALS Strength Load Cases

The alternative requirements in this sub-section only apply to the selection of metocean criteria for intact Survival/ALS strength load cases for the re-assessment of existing risers. All other load cases should be per Section 4 and API RP 2RIM.

For existing risers that were designed in accordance with API RP 2RD First Edition [S11] or API Standard 2RD Second Edition [S12], the return period may be selected for the Survival/ALS strength load case per Section 4, or per the original design basis.

For existing risers for which the metocean criteria for the Survival/ALS strength load case has increased since the original design, as measured by significant wave height, the Survival/ALS metocean conditions consistent with the original design may be used for re-assessment.

However, in no case shall the Survival/ALS strength load case have a significant wave height lower than a 200-year return period based on the metocean criteria at the time of re-assessment.

If metocean criteria used for the Survival/ALS strength load case are lower than the 1,000-year return period metocean criteria at the time of re-assessment, then the following requirements apply:

- the host FPS should, if practical, be unmanned during the event to remove any risk to people;
- the 1,000-year return period load case results shall be used to identify any vulnerabilities or weak links in the riser system and the potential consequences;
- mitigations should be identified and implemented as the operator deems appropriate to the specific situation in terms of escalation of damage into other systems and harm to the environment.

Refer to Annex A for further guidance.

9.2.3 Fatigue Re-assessment of Existing Risers

API RP 2RIM includes general guidance for considering a reduction in fatigue safety factors based on data and inspections. This sub-section provides additional specific guidance around reduction in fatigue safety factors for past damage that is consistent with API RP 2RIM. For other situations not addressed herein, refer to API RP 2RIM.

The safety factor, F_{fat}, associated with future fatigue damage shall be per Table 7.

The safety factor, F_{fat}, associated with past fatigue damage shall also be per Table 7 unless it can be demonstrated through condition data collected over the operating history of the riser that the condition of the riser is known and consistent with the assumptions used in the re-assessment, and that the load cycle history is known from sufficient direct or indirect measurements collected over the time period being re-assessed. For past fatigue damage not associated with VIV for which this can be demonstrated, the safety factor can be reduced to no less than 3, so long as the following requirements are met for the time span being considered:

- The loads on the riser are known through some combination of metocean data, correlated FPS motion data, or measured riser response data.
- The mechanical and physical condition of the riser is known through regular general visual inspection (GVI) of all components of the riser system.
- The operational history of the riser is well documented, including records of pressure, temperature, flow rates, fluid corrosiveness, production chemistry, slugging, and H_2S assessment, as applicable.
- Sufficient external and Internal corrosion data are available to ensure the analysis assumptions for past and future fatigue damage accurately reflect the corrosion conditions of the riser (i.e., the validity of S-N curve assumptions). This can be done through in-line inspections or external inspection methods provided the accuracy of the inspection tool is sufficient to make this determination. Corrosion and erosion coupon sampling and inlet separator monitoring can be used to supplement the inspections.

  NOTE: Consideration of inspection data, including corrosion data, only applies to the time span for which the data is available. For example, if corrosion monitoring has not been done routinely over the life of the riser and inspection at the time of re-assessment shows significant change in the condition of the riser, unless other data is available, conservative assumptions should be made about the condition of the riser during that time.

  Opportunity-based inspections (i.e., an inspection that is made possible through operational decisions, not required in the IM Plan) are also valid to demonstrate a lower past fatigue safety factor where quantitative inspections of retrieved riser sections based on the same design and environmental conditions are used to assess risers that remain in service. For example, a TTR that is retrieved to make way for a drilling riser to side-track a well is available for direct NDE. Taking advantage of that opportunity can provide valuable condition data for similar risers.

  It is recommended that any reduction in past fatigue safety factor include a risk assessment where mitigations are identified and implemented as the operator deems appropriate to the specific situation in terms of escalation of damage into other systems and harm to people or the environment.

The fatigue safety factor applied to past VIV damage should only be reduced if at least one of the following is available to validate the past fatigue:

- VIV riser motion measurements associated with current events from which the stress and damage can be calculated directly;
- Current measurements that can be used in conjunction with an industry calibrated VIV prediction tool.

A combination of the two above conditions may need to be considered if any of them does not cover significant portion of past duration. In any case the reduced VIV fatigue safety factor, F_{fat}, shall not be less than 3.

Refer to Annex A for additional discussion of past fatigue damage assessment.

The damage criteria for long-term fatigue in Equation (35) can be modified as follows for re-assessment of existing risers where any reduction in safety factor is proposed.

The total long-term fatigue damage, *D*, over the design life of the riser can be broken down as follows, using the Palmgren-Miner's rule:

$$D = D_{future} + D_{past1} + D_{past2} \tag{39}$$

where

D_{future} = fatigue damage that is predicted to occur the future

D_{past1} = fatigue damage that occurred in the past but is not qualified for reduced safety factor per this sub-section

D_{past2} = fatigue damage that occurred in the past and is qualified for reduced safety factor per this sub-section

The following criterion can be used in place of Equation (35):

$$(D_{future} + D_{past1}) \cdot F_{fat} + D_{past2} \cdot F_{reduced} \leq 1 \tag{40}$$

Where F_{fat} = Fatigue design factor per Table 7

$F_{reduced}$ = reduced fatigue safety factor that is no less than 3.

Refer to Annex A for additional guidance and examples.

As described in API RP 2RIM, any anomalies in the riser may be assessed using fracture mechanics to determine the appropriate inspection interval for that anomaly. If such inspections are not practical, then this could impose a limit to service life regardless of the S-N fatigue assessment.

Anomalies to be considered include the outcomes of any inspections in fabrication or during the service life of the riser. For risers originally fabricated and inspected with UT where records of accepted weld flaws are available, this data should be considered as condition data for a life extension assessment.

If an ECA was performed to determine the flaw acceptance criteria for a riser, the original ECA and the resulting flaw acceptance criteria should be reviewed as input to the evaluation of the remaining riser fatigue life and accordingly life extension. An update to the ECA based on condition data and operating data collected since installation could provide additional insight into the re-assessment.

The safety factor used for fracture mechanics fatigue assessments should be no less than half that used for S-N fatigue re-assessment per 9.2 (i.e., 5 for future damage and VIV damage), and not less than 2 for past damage that meets the criteria of this section for reducing S-N safety factors.

Alternative fatigue re-assessment methodologies, such as reliability-based assessments or use of operational or forensic data from analogous risers, can be considered where the provisions of

this Recommended Practice do not adequately address specific circumstances in accordance with API RP 2RIM.

9.3 Life Extension

Extension of the service life of a riser (also referred to as “life extension” or LE) should be addressed as an integral part of riser IM. Life extension should be considered as one of the many events identified in the IM plan that trigger re-assessment, as prescribed in API RP 2RIM.

Re-assessment for life extension should determine if the riser remains fit for service until the end of the extended service life in accordance with Section 9.2. The following should be considered:

- Review of all characteristic data, condition data, and operating data as defined in API RP 2RIM to determine how the condition of the riser has changed since installation, including all inspection reports, resolution of anomalies, past re-assessments, and monitoring data (e.g., metocean data, FPS motion data, fluid composition data, corrosion monitoring data, etc).
- Review of the original design, identifying areas where changes in riser condition may affect the fitness for service.
- Review of all riser analyses performed during the life of the riser being evaluated for life extension.
- Review of the riser IM plan and recommendations to change inspection frequencies and/or add inspection points based on review of all characteristic data, condition data, and operating data.
- Re-analyze the riser if review of analysis raises concerns based on recent inspection data.

Refer to Annex A for more discussion of life extension.

Annex A
(informative)

Commentary – Additional Information and Guidance

NOTE The sections in this Annex provide additional information and guidance on the sections in the body of this document. The same numbering system and heading titles have been used for ease in identifying the subsection in the body of this document to which it relates. Guidance is provided only on the identified clauses.

A.1 Scope

While the scope statement is clear around what is covered by this standard and what is not, there are questions that frequently arise around flexible risers, dynamic umbilicals, and composite materials.

Flexible risers

The design, manufacturing, installation, and integrity management of the various components of flexible risers are covered in detail by the API sub-committee 17 standards, API RP 17B, API Spec 17J, API Spec 17K, API Spec 17L1, and API RP 17L2. The only contributions of API RP 2RD to flexible riser design are related to riser interference, and appropriate load case development (Section 4).

Dynamic umbilicals

Similarly, the dynamic umbilical design is comprehensively addressed in API Spec 17E [S03]. Typical umbilicals might include hydraulic control lines, electrical wires, fiber optic cables or chemical injection lines. Umbilicals used for hydrocarbon transport (typically gas lift or gas injection) are generally classified as pipelines by regulators, requiring pressure design of the hydrocarbon tubing. This is also addressed in API Spec 17E [S03].

Composite risers

While there has been a good deal of work done in the industry around the potential use of composite materials such as thermoplastic composite pipe (TCP) for hydrocarbon risers, to date they have not seen wide-scale deployment for dynamic risers and are not directly addressed in this Recommended Practice. There are material standards available for different composite materials, including DNV-ST-F119 for TCP and DNV-ST-C501 [S28] for Fiber Reinforced Plastic (FRP) pipe, but they do not address riser design. It is anticipated that this will eventually be addressed in API Sub-committee 17 in a similar manner as flexible pipe, with reference to this standard where applicable..

API Recommended Practice vs Standard

The change from Recommended Practice (first edition) [11] to Standard (second edition) [12] was based on the original intention of it being an ISO standard that was later adopted by API. This was part of a broader scheme for merging API and ISO offshore standards that was later abandoned. ISO does not use the term “Recommended Practice”. All ISO standards are simply “International Standards”, so it was assumed the API adoption would also be a Standard. The distinction between API Recommended Practices and API Standards has no impact on the content or application of the content. It is merely an administrative description.

The relationship between API and ISO changed and API STD 2RD [12], second edition was issued as an API document instead but retained the Standard designation, which has created some confusion in the industry. The third edition has reverted to the more conventional Recommended Practice to align with other related API offshore design standards.

A.4 Design Load and Conditions

A.4.3 Design Load cases

A.4.3.1 Strength

a) Table 1 – Load Case Category Definitions

Four load case categories allow backward compatibility with the earlier editions and ensure consistency in how load cases are assessed, irrespective of which method the designer chooses to apply.

In API RP 2RD, first edition [S11], based on the working stress design (WSD) approach, five load case categories for strength assessment were defined: operating, extreme, survival, test, and temporary. The first four are reflected in Table 1. The temporary load case has been removed (see discussion below).

In API STD 2RD, second edition [S12], based on the limit state design (LSD) approach, three load case categories for strength assessment were defined: serviceability limit state (SLS), ultimate limit state (ULS) and accidental limit state (ALS). The SLS, ULS and ALS load case categories of the second edition had the same intent as the operating, extreme and survival load case categories of the first edition. All three of these categories are retained in this third edition. The three tiers are equivalent under both WSD and LSD approaches, but the terminology specific to each approach is retained to avoid confusion, as it is recognized that both sets of terminology are widely used in the industry.

- The Operating / SLS load case category is intended to ensure that the design is robust to the everyday loads that are expected during normal operations with a total annual probability of exceedance greater than 10^{-2}. The design factors for Operating/SLS cases are lower to ensure this. These represent the normal operating conditions expected throughout the service life of the riser. Typically, a return period of 10-years is selected for the SLS but there are situations where a 1-year return period is more appropriate. There may also be special situations where a return period greater than 10 years is appropriate.

- The Extreme / ULS load case category represents an unusual event with a combined annual probability of exceedance equal to 10^{-2} (i.e., corresponding to the traditional 100-year return period for basic design load cases), which is a well-calibrated standard used across international offshore design codes. This event is rare enough that it may not occur in the design life. Because of the rarity, higher design factors are accepted, but it is expected that after the event and subsequent inspections, the riser should be fit for continued service without repair or replacement. In some industry standards, this is simply called the “Design” case because the strength design should be controlled by this case in most circumstances.

- The Survival / ALS load case category is intended to capture abnormal or accidental events under which maintaining normal function of the riser may not be expected, but catastrophic damage or escalation of damage to other systems (e.g., FPS, mooring, wells) should be avoided. The riser may need to be repaired or even replaced, but it does not create a catastrophic outcome in terms of safety, environmental pollution, or societal consequences. It represents a test of the robustness of the design to extreme loads beyond the Extreme / ULS event. It is

intended to ensure that the design is "ductile" rather than "brittle" in its failure modes, in the sense that an incremental increase in loading does not lead to a disproportionate increase in response. Another way of saying this is that the Survival / ALS case tests for "kinks" or nonlinearities in the response curve. The failure modes of the design should be gradual rather than abrupt.

The load cases in this category have a total annual probability of exceedance of 10^{-3}, predicated on the FPS being evacuated of personnel during the Survival / ALS event. It is difficult to codify this. Some design codes simply set material yield as the criteria, but if ductile materials are used, exceeding yield does not necessarily lead to catastrophic consequences.

For regions like the Gulf of Mexico where platforms are shut-in and evacuated during Survival / ALS events, there is no risk to personnel. Depending on how the riser is shut-in or isolated, the potential environmental impact can also be mitigated. All of this should be taken into consideration in evaluating the Survival / ALS load case outcomes. The 1,000-year storm criterion is broadly considered acceptable for unmanned situations. For manned platforms, such as in the North Sea where platforms cannot be safely evacuated ahead of severe storms, the Operator should refer to regional experience and guidance in establishing manned Survival / ALS load cases or complete a full probabilistic risk assessment.

- The Test / TLS load case category defined in this edition is equivalent to the test load case category defined in the first edition. This category is to be used to represent hydrotesting of the riser system only. It is included as a specific category to ensure backward compatibility with the first edition, wherein hydrotesting is assigned a specific allowable working stress between the allowable working stresses of the extreme and survival categories. The introduction of the test limit state (TLS) load case category in the limit state design approach is an addition to the three load case categories defined in the second edition. In the second edition, hydrotesting was included as an ALS case with no specific combined load criteria design factor.

- The Temporary load case category defined in the first edition has been removed from this edition. In practice, temporary load cases were assessed in a manner identical to extreme load cases in the first edition as the allowable working stresses were the same for both categories. Furthermore, 'temporary' is also recognized to be a subjective term and its use in assigning load cases to categories is open to interpretation. This edition uses the terms 'normal temporary events' and 'abnormal temporary events' to describe load cases that should be assigned to the Operating/SLS and Extreme/ULS categories, respectively.

The normalcy or otherwise of a load case should be defined based on its annual probability of occurrence, to be consistent with the load case category definitions. For example, the normal operating mode of a production riser is likely to be the transmission of hydrocarbons from a subsea well to a processing facility. The same riser may regularly be shut-in for short periods of time. Shut-in operations in typical everyday sea states would be an example of a normal temporary event. Construction loads may also be considered normal temporary events. Extended shut-in or emergency shut-down (ESD) of the same riser, which may last through a 100-year return period storm would be an example of an abnormal temporary event. Other examples may include operating with one mooring line failed during a 1-year storm, or shutting-in a TTR with its inner annulus evacuated.

b) Developing Intact and Damaged Load Cases

Load cases should be assigned to categories based on their combined annual probabilities of exceedance. This is the probability that the combination of loads that form the load case will occur, or be exceeded, simultaneously within a year. It is calculated by multiplying the annual probabilities of exceedance of the environmental load, the functional load and the accidental or construction load (if any) together.

EXAMPLE Consider a riser exporting hydrocarbons at normal operating internal pressure and temperature. Here the annual probability of the functional load is at, or close to 1 (10^0). There are no construction or accidental loads to consider. When operating in a 10-year return period storm (annual probability of exceedance = 10^{-1}), the combined annual probability of exceedance of the load case is 10^0 x 10^{-1} = 10^{-1}. As this is greater than 10^{-2}, this should be assigned to the Operating/SLS load case category.

The same riser, exporting hydrocarbons at normal operating internal pressure and temperature in a 100-year return period storm is an example of an extreme/ULS load case, as the combined annual probability of exceedance is 10^0 x 10^{-2} = 10^{-2}.

Now, consider the riser undergoing a planned shut-in event that occurs once every two years, and has a duration of at most a week, or approximately 0.02 years every two years. The joint probability of this event with a 1-year return period storm occurring is considerably lower, closer to annual probability of exceedance of 10^{-2}, so this should be considered an Extreme/ULS event.

Finally, it may be necessary to carefully select the environmental load and functional loads associated with abnormal, accidental events to ensure they are properly assessed. For accidental scenarios involving the riser or its supporting structure or tensioning system, the annual probability of exceedance of such an event should be assessed and load cases constructed accordingly with the appropriate joint probability of occurrence. This assessment should take into consideration the duration of the damage before it can be adequately repaired, as well as what intermediate measures can be taken.

A good rule of thumb used in FPS design codes (and recommended in 4.3) is to take the intact ULS and ALS cases and reduce the environmental return period by a factor of 10. This is based on the assumption that repairs will take time, but mitigations can be made, such as shutting in the riser and making adjustments to ballast, mooring system or tensioner systems, and should also be taken into consideration.

EXAMPLE – A top-tensioned riser is supported by four hydraulic cylinders. One cylinder breaks unexpectedly. The probability of a cylinder completely parting is low, say 10^{-2} or less. So, to reach a combined probability of exceedance of 10^{-2} (ULS), one would consider an everyday sea state, or for 10^{-3} (ALS) a 10-year seastate. And if the cylinder is easily repaired or replaced with a spare onboard in a couple of days, this may be the only load cases required. However, if repairs are going to take months, the exposure goes up quickly and a longer return period event should be used. The damaged ULS would become a 10-year storm, and the damaged ALS would become a 100-year event, as shown in the example in Table 2.

For accidental events related to the FPS supporting the riser, the accidental cases corresponding to damage to the FPS or its mooring system should be commensurate with the design standards used for the FPS and its mooring system (e.g., API RP 2FPS, API RP 2T, API RP 2SK). These are typically a combination of the damage plus a reduction in return period by a factor of 10. This is a bit conservative in that it implies a probability of exceedance of 10^{-1} for the damage, which is generally not the case. However, if the damage does occur (e.g., hull compartment flooded or mooring line parted), the riser remaining intact is paramount. If the FPS is classed, the Class Society Rules should also be considered in defining damaged load cases.

c) Table 2 – Examples of Strength Load Cases

A representative example of a strength load case table is presented in Table 2, which lists some of the typical load cases for TTRs and SCRs. Load cases should be added, deleted, or amended based on the riser functional requirements and operational environments of specific projects. Load cases may vary depending on the type of riser, host vessels (e.g., TLP, Spar, Semi, FPSO), operating practices, and field location. The design criteria for different types of load cases are not included in this table but are described in Section 5.

Testing and Temporary Load Cases

In the first edition, temporary conditions included riser transportation, installation, retrieval, and testing. In this edition, construction loads covering the riser transportation and installation are categorized to Operating/SLS as normal temporary events. Since Operating/SLS uses 2/3 of yield as the allowable stress, and the test case uses 90% of yield as the allowable stress in first-edition, hydrostatic testing is separated from the SLS construction case and defined as a Test/TLS case in this edition. Depending on the field location and the construction schedule window, the riser maximum construction case can be up to a 10-year loop current or 10-year winter storm (load case 1).

A new TLS case is introduced in the current edition for the riser hydrotest (load case 6). The hydrotest, which usually uses seawater as the test medium, is typically allowed to be performed during a 1-year winter storm or a better environment.

Normal operating/SLS and Extreme/ULS load cases

Riser normal operating or extended shut-in conditions are defined as SLS and need to be checked to ensure the riser will function normally throughout the event (load case 2). SLS cases are not typically the governing load cases for the riser design. The maximum operating condition is defined by the operator as the maximum permissible for the system. The typical maximum operating condition for the Gulf of Mexico is a 10-year loop current or a 10-year winter storm.

The riser is designed to withstand the extreme environments of 100-year hurricane in the Gulf of Mexico, either in normal operating or extended shut-in conditions (ULS load case 3 and 4). Production risers may be displaced with dead oil to limit the risk of hydrate formation during an extended shut-in that can last for days, weeks, or months in the case of a planned turnaround. Since the riser surface pressure and content density are different, both cases are presented for ULS examples.

Survival/ALS load cases

Survival/ALS cases, as defined in Table 1, occur when the riser experiences survival environments of 1,000 year return period (load case 5) or rare accidental loads (load case 7 to 10), including casing/tubing leak for TTRs, failed mooring line(s), flooded compartment(s), or damaged tensioner(s). In the example shown in Table 2, a probability of exceedance of around 10^{-1} is expected for failure of a single mooring line, thus the extreme environments of 100-year hurricane is considered to achieve the combined annual probability of exceedance of 10^{-3} required in the ALS case (load case 7).

Note that the load cases listed in Table 2 are only examples. It is the responsibility of the Operator and the designer to expand on this list based on the type of riser, the environments, the construction method and the operational conditions. The requirement is to capture all combinations of loads and to categorize them accordingly, per the definitions in Table 1.

There may be more than one environmental event in each load category. For example, in the Gulf of Mexico, ULS and ALS events for hurricanes and loop currents should be included. Refer to API RP 2MET for guidance on environmental events.

A.4.3.2 Fatigue

Fatigue load cases

Load cases should be selected considering the resulting riser response. In other words, the highest values of environmental loading may not lead to the greatest fatigue damage.

For example, currents applied to wave seastates will dampen both FPS and riser responses. Metocean statistics provide a range of associated currents for a given seastate. Selecting the highest possible associated current may appear conservative, but because of the damping effect, it may actually be unconservative.

Riser response sensitivity to different types of loading can also vary for different types of risers. Care should be taken that the load cases reflect an accurate and appropriately conservative response for the riser.

Single-event fatigue

The riser single-event fatigue response should be assessed assuming continuous exposure to Extreme/ULS and Survival/ALS storm and current events, such as hurricanes and loop currents, with the appropriate return periods (100-yr for Extreme/ULS, 1,000-yr for Survival/ALS). Survivability of the riser under continuous exposure to the events is established by conservatively assuming a single constant environment heading over the entire exposure time or by applying the directional wave storm motions. Typically, a 3-hour duration event is considered covering the peak of the appropriate storm, but a longer duration event with the ramp up and ramp down stages of the event can also be used depending on the sensitivity of the riser to such events.

For sustained current events (e.g., Gulf of Mexico Loop Current or other oceanic current), the expected duration of the event is much longer than three hours and the appropriate duration should be considered. Typically, 30 hours has been used without additional information. Refer to API RP 2MET for guidance in developing single-event fatigue current cases.

Fatigue due to slugging

Slugging addresses the potential for fatigue caused by a riser's response to slug flow especially for steel catenary risers and steel lazy wave risers. Refer to DNV-ST-F201 and Campbell, *et al* [A21] for additional information and guidance.

A.5 Design of Pipe

A.5.1 Overview

A.5.1.1 Objective

Most risers designed to date have followed the WSD design method of API RP 2RD, first edition [S11], published in 1998. While API Standard 2RD, second edition [12] was issued in 2013 and prescribes only LSD design methods. Both are acceptable design methodologies that produce safe risers, and in hindsight, the second edition should have left open the used of WSD. The present, third edition, has brought together both the WSD method of first edition and the LSD methods of second edition, although the second edition LSD Methods 2 and 4 have been consolidated, and Method 3 removed. The third edition now includes three methods for combined stress design –

- WSD, based on API RP 2RD, first edition [S11]
- LSD Method 1, similar to Method 1 in API Standard 2RD, second edition [S12]
- LSD Method 2, incorporating Method 2 and Method 4 in API Standard 2RD, second edition [S12]

Figure 3 illustrates the design process through a flowchart, referencing the relevant subsections of this Recommended Practice.

In linear elastic response, i.e., stresses lower than the yield stress or moments lower than the yield moment, the WSD method is conservative. This method has been validated by more than a quarter century of application including designs that have endured severe hurricane conditions well beyond the original design load cases and performed safely and as anticipated.

Typically, linear elastic material properties are used at the inception of the design process. For elastic response, i.e., stresses lower than the yield stress or moments lower than the yield moment, a good approach is to first check the analysis results using either the WSD or LSD Method 1. If the criteria are met, then, the design is complete, and no further action is required. Otherwise, the analysis results can be checked using LSD Method 2. If Method 2 criteria are met, then the total strains need to be verified not to exceed the allowable limits in 5.3.3. This is a guardrail against buckling-collapse that may be associated with the high strains allowed by Method 2.

For inelastic response, i.e., stresses higher than the yield stress or moments higher than the yield moment (where linear material property overestimates the stress or moment and underestimates the strains), nonlinear material properties can be used. This can be either:

- elastic perfectly-plastic properties;
- elastic linear-plastic properties;
- the stress-strain curve (or the corresponding moment-curvature) from actual testing of similar pipe;
- or the Ramberg-Osgood approximation.

Lower and upper bound curves may be used in order not to underestimate the strains and stresses, respectively. Then, the stress results can be checked using WSD, or LSD Method 1 at first, and LSD Method 2 if necessary. And the total strains cannot exceed the allowable limits as per 5.3.3.

The resulting ovality should also be checked and its impact on the collapse pressure of the pipe assessed. It should be noted that in Figure 3, the strains for typical D/t ratio are not expected to be an issue for WSD (stresses below yield stress) and LSD Method 1 (moment below yield moment); however, the strain check is added to cover cases where:

$$D/t > \sqrt{\frac{E}{[S*(1-\nu^2)]}} \tag{41}$$

Extreme Value Estimation

The extreme values calculated for a particular load case should be based on at least a three-hour storm duration. Either the most probable maximum or expected maximum value may be used. There is no compelling statistical reason for choosing one over the other in this context. Both are accepted means of calculating short-term extreme values. The average of maximum response values obtained from multiple realizations can also be used as the expected maximum value, using at least ten realizations.

Refer to Ochi (1973) [A1], Stanisic, et al (2017) [A29], and DNV-ST-F201 [S29] for further guidance on the estimation of extreme values.

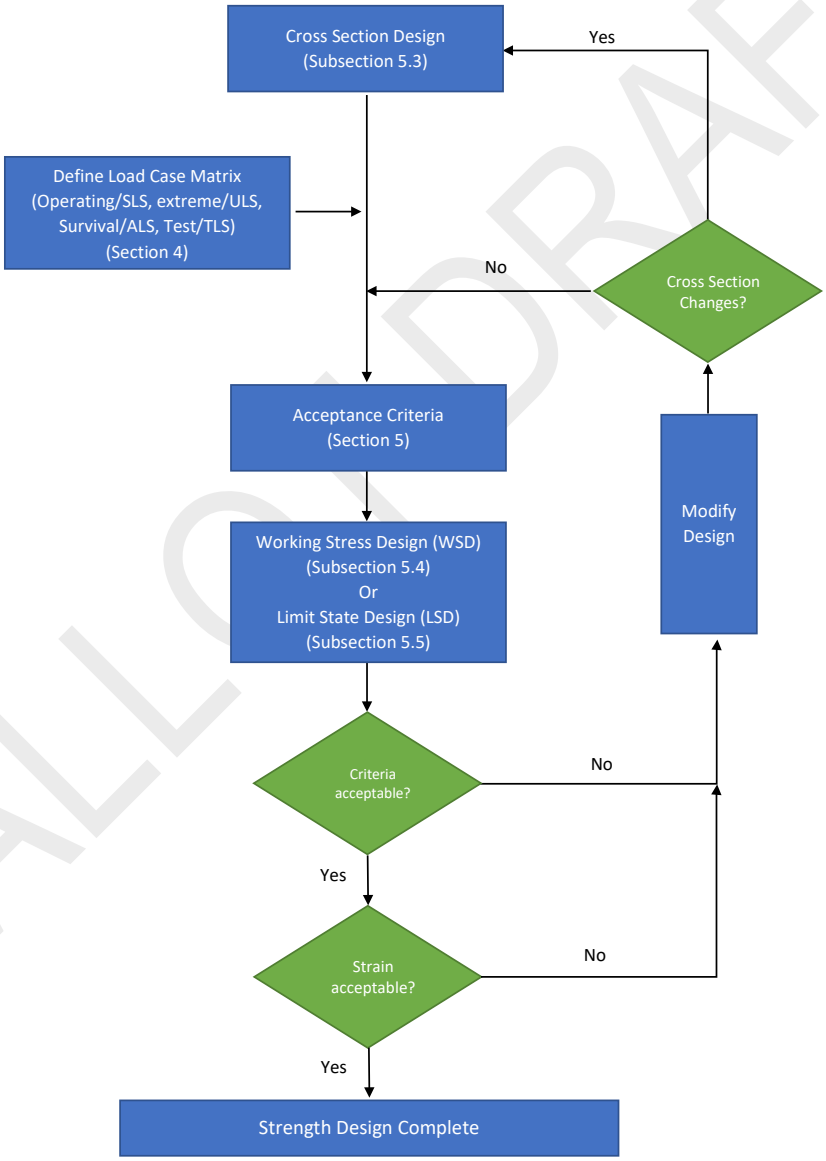


Figure 3 — Design Process

A.5.2 Pipe Capacity

A.5.2.2 Burst Pressure

The theoretical burst equation for capped end pipe made from elastic, perfectly plastic material that obeys the von Mises yield function is

$$P_b = \frac{2}{\sqrt{3}}\, S\, ln\left(\frac{D}{D-2t}\right) \tag{42}$$

where

S = yield strength

D = outside diameter

t = wall thickness

Data collected from burst tests performed on API Spec 5L and API Spec 5CT pipe show a dependence of burst pressure on the yield to ultimate ratio Garrett (1998) [A2]. Others (Terada, 2009) [A3] have indicated this as well on a wide variety of pipe. Thus, replacing, yield, S, with $(S+U)/2.25$, where U = ultimate strength, eliminates the dependence on yield to ultimate ratio. This form of the equation provides a better fit to burst test data with a lower coefficient of variation. The burst tests referred to are recorded (Garrett, 1998) [A2] and include 267 specimens and cover a wide range of variables such as diameters from 2.65 inches to 20 inches, D/t ratios from 6 to 32 and yield from 48 ksi to 138 ksi. Of the 267 test specimens, five samples were plastically bent to a strain of 3-4% prior to the burst test. These were included to demonstrate that such bending does not reduce the burst capacity of the pipe, as observed. Note that $(S+U)/2.25$ is slightly less than yield for pipe with high yield to ultimate ratio, such as X-65 and X-80 grades.

For design purposes a minimum burst pressure is to be computed so that no pipe that meets specification will burst below that pressure. A reduction to account for minimum wall thickness is included. The reduction is 0.875 based on standard wall thickness tolerance for API Spec 5L and API Spec 5CT pipe. The reduction for minimum wall thickness is applied outside the natural log argument because the wall thickness to use inside the natural log argument is the nominal wall thickness. Consequently, the coefficient multiplied to the sum of the yield and ultimate, $(S+U)$, becomes a value of 0.45 ($0.45 = 0.875 * 2/\sqrt{3} * 1/2.25$).

More recent tests of thick-wall high strength pipe materials recorded in Shilling, *et al*,(2011) [A4] confirm the reliability of the burst equation.

A.5.2.3 – Collapse Due to External Pressure

The external overpressure to cause unbent pipe to collapse (flattening of the cross-section or yielding) is predicted by one of two equations. The simpler formula is Equation (2), which was first presented in Murphey and Langner (1985) [A5] and has been widely used in Gulf of Mexico pipeline design. It uses a combination of the elastic buckling collapse pressure (P_{el}) and the yield pressure (P_y). It has been shown to acceptably predict collapse pressure over a wide range of D/t ratios. The collapse pressure for thicker pipe (low D/t ratio) is governed by the external pressure that causes compressive yielding in the hoop direction, while thinner pipe (high D/t ratio) fails in the elastic buckling regime. The transition from one failure regime to the other occurs at $P_{el} = P_y$ or $\frac{D}{t} = \sqrt{\frac{E}{[S(1-\nu^2)]}}$ where S is the yield strength. Experiments show that this equation also does a good job of providing a transition between the two failure regimes.

Note that this equation is not a prediction of the minimum collapse pressure, therefore a design factor is required to ensure the pipe capacity exceeds the expected external pressure loading. No influence of pipe ovality is included in Equation (2), however studies provided in Fowler and Langner (1991) [A6] and Nogueira and Harrison (2011) [A7] have shown that it matches well to the collapse pressure derived by Timoshenko and Gere as long as the initial ovality is small.

Multiple equations were developed to include explicitly the impact of pipe ovality by introducing a so-called imperfection function and the one proposed by Murphey and Langner (1985) [A5] was included in API RP 2RD 1st edition. However, Equation (2) is used in API RP 1111 and in an effort to maintain compatibility to the extent possible with API RP 1111 (a riser is an extension of the pipeline), only Equation (2) is kept in this 3rd edition.

A.5.3 Design for Pressure

Pressure containment is paramount for pipelines, flowlines and risers. Therefore, initial pipe wall thickness size is dictated by internal and external pressure loading. Once the initial wall thickness is determined, other loads (i.e., tension and bending) from the design load cases can be obtained from analyses and used to check against criteria defined in either 5.4 or 5.5. Adjust the wall thickness or the design as needed until all criteria (including fatigue) are met.

Using combined pressure and bending in determining the initial wall thickness will increase the likelihood that the initial wall thickness is sufficient when other loads are considered.

A.5.3.1 Internal Pressure

Examples of the internal pressure exceeding the external pressure include high design pressure, shut-in pressure with subsea valves open, hydrostatic test pressure, and incidental pressure such as tubing leak when the production riser serves as casing or pressure in a drilling riser due to a kick (hydrocarbons from the reservoir entering the wellbore). The design pressure is the maximum pressure that will be seen for an extended period of time during normal operations.

A.5.3.2 External Pressure

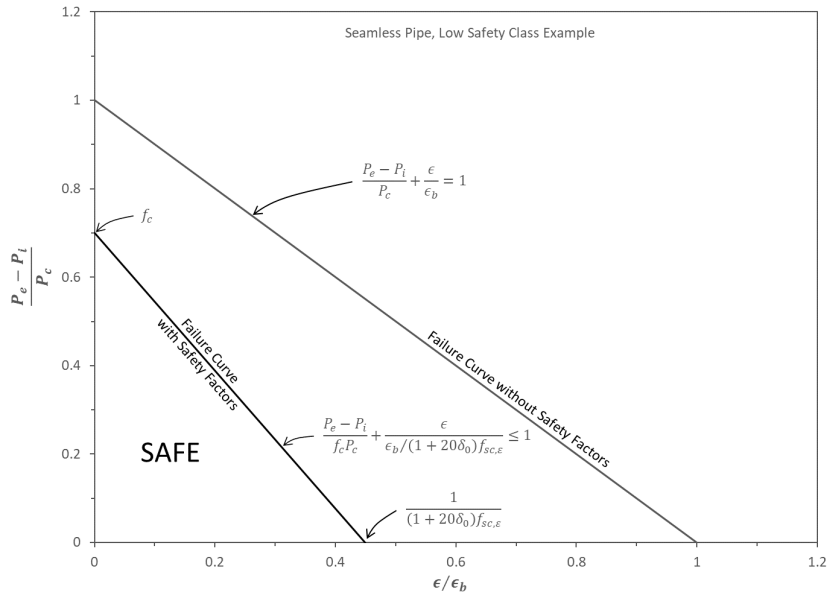
Risers can be subject to conditions where the external pressure exceeds the internal pressure. Examples include installation of catenary risers with the pipe empty, export catenary risers in deep water where the external hydrostatic pressure at the bottom exceeds the internal pressure, and annulus evacuation in drilling risers due to loss of circulation during drilling operations.

A.5.3.3 Combined Bending and Pressure

Numerous experiments have been performed to determine the failure limit when pipe is subjected to combined external overpressure and bending. The records of such experiments are shown in plots in Murphey and Langner (1985) [A5], Fowler and Langner (1991) [A6] and Nogueira and Harrison (2011) [A7]. Most plots are normalized. External overpressure, which is plotted on the Y-axis, is normalized by dividing by the calculated collapse pressure (Equation (2)), and the bending strain is normalized by dividing by the critical bending strain (Equation (5)).

The failure curve (without any safety factors) for combined external pressure and bending is shown as a straight line from 1.0 on the Y-axis to 1.0 on the X-axis. Nearly all experimental data points lie above and to the right of this straight line. With factors of safety applied to both external pressure and bending, the envelope bounding the safe region moves down and to the left as shown in Figure 4.

Figure 4 — Combined Bending and External Overpressure Capacity Envelope



Progressive Ovality:

Ovality formulae for pure bending and pure pressure are available in Murphey and Langner (1985) [A5]. However, formulae for combined pressure and bending or combined pressure, bending, and tension are not available. Ovality is most likely to occur at the sagbend of SCRs where bending is typically dominant. As such, the formulae for bending may be used. Alternatively, FEA simulating the load history may be performed to determine the extent of ovality.

In general, the experiments demonstrate that the pipe must be bent well beyond yield (i.e., bending strain well exceeds yield strain) before affecting the collapse pressure. As long as combined loads remain in the elastic range, the criteria given in 5.4 or 5.5 are adequate. When the predicted riser pipe curvature during any design load case produces strains in the inelastic range, the criteria given in 5.3.3 should be checked.

Appropriate modeling of nonlinear material behavior should also be employed to estimate the curvature or bending strains. Cyclic loading into the inelastic range should be avoided. Progressive ovality like that shown in Murphey and Langner (1985) [A5] will result and will greatly affect collapse capacity and fatigue performance in a negative manner.

Cross-section ovalization of pipes under bending and pressure is smaller in the case of internal overpressure compared to zero internal pressure or external overpressure and their buckling resistance is higher. However, the effect of internal overpressure is not considered in Equation (13) for conservatism.

A.5.3.4 Propagation Pressure

The pressure at which a pipe buckle (flattening of the pipe cross-section) propagates (advances along the length of the pipe run) is less than the external pressure that will cause the pipe to collapse. However, setting pipe wall thickness to guard against collapse propagation is not the generally accepted practice. It takes an accidental event to compromise the integrity of the pipe and initiate the buckle. Once a buckle propagates, remediation typically involves full replacement of the riser. Use of buckle arrestors can limit

this to replacement of local segments. When the wall thickness required to resist buckle propagation is just slightly larger than that required to resist collapse and is economically practicable, it could be useful to select the larger wall thickness and avoid the risk of buckle propagation.

A.5.4 Working Stress Design Criteria

The first edition of API RP 2RD used von Mises yield criterion to ensure the riser is not subjected to loading conditions that cause structural yielding. For the pipe components of the riser, the computed von Mises equivalent stress evaluated at mid-wall (analogous to primary membrane stress) is not to exceed the allowable stress. Non-pipe components are also required to adhere to the same criteria except primary membrane plus bending. Primary membrane plus bending plus secondary stresses need to also be checked, similar to design by analysis methods presented in ASME BPVC, Section VIII, Div 2. These design criteria are carried over to this edition of API RP 2RD without alteration because this approach has been demonstrated to provide satisfactory designs proven by riser systems that have endured decades of service life.

Depending on the method selected by the designer, the von Mises equivalent stress may be computed using the formula given by Equation (22) or the equally useful primary membrane stress formula provided as Equation (26). In both formulas, the hoop, radial and axial stresses are the principal stresses.

A.5.4.1 Stresses to Consider

Bending Secondary and Condition Factor:

A condition factor with a value of 0.85 may be multiplied to the bending moment when it can be confirmed that bending is secondary. The factored bending moment is then used to compute the von Mises equivalent stress at pipe mid-wall as if bending is primary. Use of the condition factor when bending is secondary is also consistent with DNV-ST-F201.

Bending can be considered secondary when:

- The pipe is bent into final shape that cannot change further, such as a pipe bent around a reel, or a pipe conforming to a fixed terrain, or
- The displaced shape is not dependent on bending stiffness but instead is a function of effective tension distribution.

In other words, it is secondary when the equilibrium shape is displacement controlled.

The sag-bend of a catenary riser takes its shape based on the ratio of the horizontal tension to unit weight in seawater, while the magnitude of bending moment in the riser is dependent on its bending stiffness. This holds true for the dynamic and static equilibrium shape as long as the effective tension is positive (no effective compression).

When the dynamic response effective tension goes into compression, (typically in the sag-bend of a catenary riser where the effective tension is smallest) then the equilibrium shape is not completely displacement-controlled nor load-controlled but somewhere in between and bending moment is not entirely secondary. Assessing maximum bending strain rather than maximum bending moment is advised. Reasonable steps are to be taken to estimate the maximum curvature (where bending strain, ϵ, is equal to $K(D/2)$ and where K is the curvature and D is the nominal diameter of the pipe) under such circumstances.

Riser drag modeling and material nonlinearity can be influential in predicting maximum bending strain as well as the interaction with the seafloor. Refer to Annex B for guidance on selection of hydrodynamic coefficients and modelling of riser / soil interactions.

Also, account should be taken for strain amplifications where uniformity of riser properties is interrupted, for example counterbored ends of pipe at weld joints.

In practically all situations, the upper region of the riser experiences considerable drag loading from direct action of waves and from motions of the FPS, thus this region is load-controlled, and bending is not secondary. Bending moments decay exponentially away from the highly loaded region. In deep water the sag-bend curvature of the riser is only marginally influenced by the loads in the upper region.

The last paragraph of 5.4.1 allows for use of nonlinear material models, noting that bending strain is limited by the criteria in 5.3.3. There is one hypothetical *caveat* to this, and that is if there were to be significant axial compressive strain, in addition to bending strain, that was already at the limit of 5.3.3. This is not typical of SCRs, TTRs or FSHRs, but if for some reason an unusual and unanticipated riser configuration leads to a significant amount of axial compression strain, this should be added to the bending strain in performing the checks in 5.3.3. This is not required by this recommended practice.

A.5.5 Load Limit State Design Criteria – Methods 1 and 2

Derivation of the load combination design equations for load limit states Method 1 and Method 2 are given in Kirkemo (2001) [A8]. Method 1 is called the elastic limit state, where the onset of yielding within the pipe body marks the limit. Method 2 is described as the cross-section limit load because the entire cross-section has reached the limit stress in both tension and compression. In both these limit states the following general assumptions are made:

- von Mises yield criterion
- linear geometry
- small strains
- no strain hardening (elastic perfectly plastic stress-stain curve)

By assuming linear geometry and small strains, it is implied that effects from diameter change, wall thickness change, pipe ovalization, or the potential for local buckling are not accounted for.

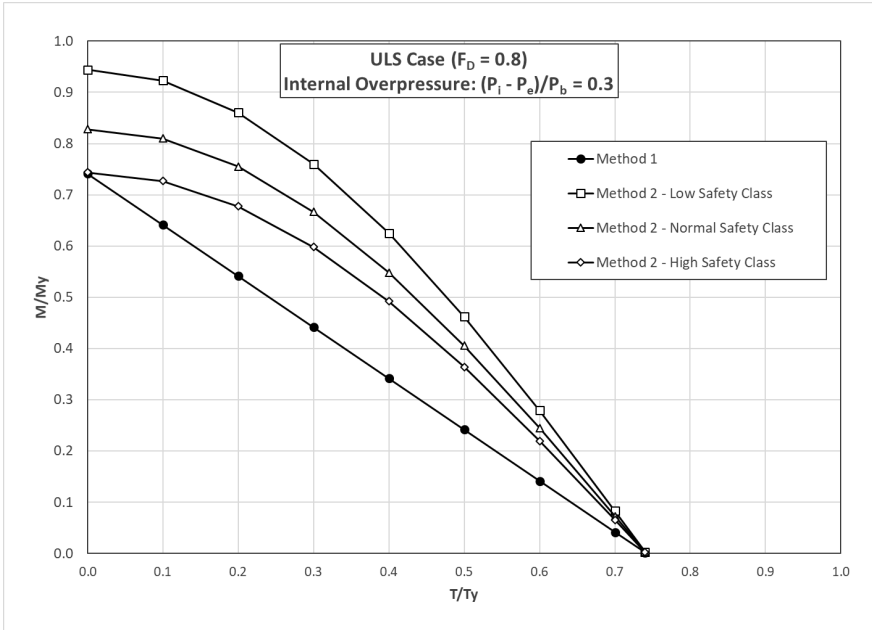
Similar to working stress design (5.4), safety class factors are not proposed for load limit state design Method 1. However, Method 2 is burdened with safety class factors because this method pushes the design envelope beyond that of working stress design and Method 1. This is demonstrated by the normalized load capacity chart for a generic riser presented in the Figure 5 below. The three curves representing the three safety class levels applied to Method 2 are above the straight-line defining Method 1 normalized load capacity. To portray typical design considerations, a constant pressure differential across the wall of the pipe is assumed, while the tension and bending capacities are normalized by load at yield. Some features to note about the normalized load capacity chart are:

- The curves converge to the tensile capacity at zero moment
- At zero tension (pure bending), Method 2 moment capacity using the high safety class design factor is practically the same as Method 1 moment capacity

The last paragraph of 5.5.1 allows for use of nonlinear material models, noting that bending strain is limited by the criteria in 5.3.3. See A.5.4.1 (last paragraph) for a discussion on the use of bending strain vs. total strain.

Use of the condition factor when bending is secondary is also consistent with DNV-ST-F201.

Figure 5 — Tension-Moment Load Interaction Chart



A.5.5.3 Method 2

Equation (8) is based on elastic perfectly plastic material properties where the stress remains constant with increasing strain after reaching yield "S". However, in reality, the stress-strain curve flattens but still with positive slope due to strain hardening with small increase in stress producing large increase in strain until the ultimate strength capacity is reached (onset of necking and softening). This occurs at approximately 15% strain for X65 steel and similar grades and corresponds to the actual Mp, which is approximately 10% higher than that based on elastic perfectly-plastic material. Thus, once the bending moment exceeds the yield moment (pipe mid-wall reaching yield strength), small increase in moment can lead to large increase in strain. Likewise, a small decrease in moment such as 10% can lead to large decrease in strain.

The bending strains may be excessive when the bending moment approaches the plastic moment capacity M_{max} taking into account tension and pressure as given by the following equation:

$$M_{\max} = M_{\mathrm{p}}\sqrt{1-\left(\frac{p_{\mathrm{i}}-p_{\mathrm{e}}}{p_{\mathrm{b}}}\right)^2}\cos\left(\frac{\pi}{2}\frac{T/T_{\mathrm{y}}}{\sqrt{1-\left((p_{\mathrm{i}}-p_{\mathrm{e}})/p_{\mathrm{b}}\right)^2}}\right) \tag{43}$$

For moments smaller than 90% of M_{max}, the strains are likely to be small and not a source of concern except for high yield-strength pipe or low diameter-to-thickness ratio pipe. For moment derived from analysis larger than 90% of M_{max}, the strains are likely significant.

A.5.6 Fatigue

A.5.6.1 General

In practice, the riser design contractor may be different from the construction contractor, and even if they are under a single contract, they tend to be very different parts of the company. Hence, interface management is very important. It is a good practice to allocate a fatigue damage budget for construction activities so the design and construction contractors can work independently. For example, if the construction budget is set at 5% of the allowable damage, then the designer can work with 95%. When the design and installation engineering are complete, it is possible that the balance has shifted slightly.

After the riser is fully commissioned, a reckoning should be made of the actual fatigue damage incurred during construction activities to be included in the IM data passed over to the Operator for future re-assessments.

A.5.6.3 – Low-Cycle Fatigue (i.e., Inelastic Range)

Methodology

Low-cycle fatigue in a riser system is generally associated with rare occasions where a few load cycles generate stress ranges that go into the inelastic range, *i.e.*, where $\Delta\sigma/2$ exceeds yield. In such cases, the fatigue damage caused by the high load cycles may not be adequately captured by the S-N curve approach. The fatigue damage due to these inelastic cycles can be calculated using a strain *vs.* number of cycles to failure (*ε-2N*) approach, as outlined below. It can also be derived from mechanical testing.

Curves used with the *ε-2N* approach are not as well established as those associated with the high cycle (elastic range) fatigue *S-N* approach. A range of well-established *S-N* curves are available in several industry standards. While *ε-2N* curves for some grades of steel may be available in the literature, a considerable number of tests will likely be required to establish *ε-2N* curve coefficients that have the necessary statistical significance for a particular situation.

The general form of the *ε-2N* relationship (i.e., Coffin-Manson relation) is given in Equation (44), where cycles of controlled strain amplitude are applied to determine the number of cycles to failure.

$$\varepsilon = a\,(2N)^b \tag{44}$$

where

ε	is the plastic strain amplitude = $\varepsilon_t - \varepsilon_e$
ε_t	is the total strain amplitude
ε_e	is the elastic strain amplitude obtained from the stabilized cyclic stress-strain curve
$2N$	is the number of reversals to failure
N	is the number of cycles to failure
a, b	are the fatigue ductility coefficients

Coefficients *a* and *b* are the intercept with the y-axis and slope, respectively, of the line on a *log-log* graph that is two standard deviations or more below the mean line that fits the *ε-2N* test data.

The *ε-2N* curve used for fatigue design should be qualified through testing. Statistically appropriate estimates of the fatigue ductility coefficients should be obtained from strain *vs.* number of cycles to failure

ε-2N tests of the pipe or weld material. The stabilized cyclic stress-strain curve and *ε-2N* tests are established from cyclic loading and unloading where the strain amplitude is controlled.

Refer to ASTM E606/E606M for standard test method for strain-controlled fatigue testing and ASTM E739 for standard practice for statistical analysis of strain-life fatigue test data.

Low cycle fatigue damage can be calculated using Palmgren-Miner's rule as given in Equation (34) with the substitution of strain cycles in place of stress cycles and plastic strain amplitude in place of stress range.

Reeling Cycles

For reel-lay operations, a limited number of large (inelastic) strain cycles occur. This should be accounted for in the fatigue damage prediction and during weld verification testing. The weld fatigue testing program should include bending and straightening of the pipe test specimen to curvatures that simulate the reeling and unreeling process prior to the high cycle fatigue tests.

A.5.6.4 Long-Term Fatigue

Sources of long-term fatigue

Long-term fatigue comes from various sources of environmental loading that occur throughout the service life of the riser. Refer to API RP 2MET for requirements and guidance on the development of appropriate met-ocean conditions for fatigue assessment.

Conditions that induce long-term fatigue damage include the continuous wave, wind, and current loads that are ever-present with varying levels of intensity.

- Waves generate wave-frequency and low-frequency loads on the FPS, leading to motions that in turn excite riser dynamic, as well as direct loads on the riser.
- Current and wind loads affect the static offset position of the FPS and static shape of the riser, which in turn indirectly influence the FPS and riser motions. Current can also induce VIV of the riser or VIM of the FPS (in turn moving the riser).
- Wind loads also have a dynamic component that generates low-frequency motions of the FPS.

FPS motions also vary significantly depending on the type of FPS (e.g., TLP, Semi, Spar, FPSO), the mooring system, and the other risers connected to it. Hence, a fully coupled motions analysis model, calibrated by model tests, is important for riser design. For more guidance on the motion analysis of a FPS, refer to API RP 2FPS and API RP 2T and Annex B.

These environmental conditions are usually represented in the form of a scatter diagram, which is essentially a multidimensional histogram of combined wind, wave and current conditions derived from a met-ocean database based on measured data and/or hindcast data representing the statistical make-up of the environmental conditions. The structure of the scatter diagram depends on the local environment, but in most situations, it can be distilled to a two-dimensional histogram based on significant wave height and spectral peak period, with associated combinations of wind and current based on correlations derived from the met-ocean database.

The scatter diagram should represent the full range of conditions, which may include winter storm fronts, local squalls, and tropical cyclonic conditions (i.e., tropical storms, hurricanes, typhoons). In this way, the complete histogram represents the wind, wave and current conditions experienced by the riser system and the supporting FPS.

Other met-ocean conditions such as prevailing oceanic currents (I.e., not associated with local storms) such as the Loop Current in the Gulf of Mexico, or long-period swell should also be represented in scatter diagram form.

Design factors

The design factors specified in Table 7 are required minimum values. An operator may choose to further discount specific sources of fatigue. For example, some operators apply an additional safety factor to fatigue from VIV of the riser, typically a factor of 2. The rationale for this is based on the relatively high level of uncertainty around VIV loads and response compared to wave loading, and the relatively low cost of including additional VIV suppression during installation compared to retrofitting VIV suppression on the riser in-service should more VIV than predicted occur. This is primarily an economic decision.

The same rationale may be applied to other sources of fatigue where there are unusual circumstances leading to higher-than-normal levels of uncertainty, such as novel riser designs, unusual FPS configurations, or sources of fatigue having limited data available to determine accurate loading.

Fatigue damage and safety factors

One of the most confusing issues around riser fatigue for those not familiar with fatigue design is the use of the term “fatigue life”. This term is deliberately not used in this recommended practice. The terms “design life” and “service life”, which are not the same, are defined in Section 3. Service life is the anticipated duration the riser will be in service, whereas design life is the time until the riser exceeds the allowable accumulated long-term fatigue damage. For most locations on a riser, the design life greatly exceeds the service life, but the design life of a riser is determined by the location with the greatest damage, but still in excess of the service life.

The long-term fatigue criteria in Equation (35) is based on fatigue damage, not “fatigue life”. The safety factors presented in Table 7 are applied to Equation (35) to provide the allowable fatigue damage during the design life. Conversations about fatigue design should be in terms of calculated damage vs allowable damage. For example, for a non-retrievable riser, the allowable damage is 1/10 = 0.10, or no more than 0.10 / (design life) damage annually. This is useful since scatter diagram data is typically annualized.

All calculations are based on damage and all technical discussions should remain focused on damage. The only value in referring to “fatigue life” is when engaging with stakeholders who are primarily interested in how long a riser can remain in service – i.e., remaining fatigue life. In the design phase, it is easy to invert damage to calculate “fatigue life”, which is useful to satisfy the various stakeholders in the design phase, including regulators. Using these terms in other contexts such as integrity management or life extension can be ambiguous and creates communication problems.

1) “Factored fatigue life” – The design life is prescribed in the basis for design. The estimated life is required to be at least F_{Fat} times the design life. Some people multiply the design life by F_{Fat} and compare it to the calculated life, calling it “factored fatigue life” while others do the opposite referring to the calculated damage (inverted) as “factored fatigue life”, creating confusion. This can all be avoided by using damage and allowable damage as the measure of fitness for service. Unity checks can be made of the ratio of calculated damage over allowable damage if that makes it clearer.

2) Integrity Management over the life of the riser – As soon as the riser is installed, the meaning of “design life” is lost. Actual fatigue damage does not accrue exactly as predicted, particularly when it comes to VIV and VIM induced damage, which can be event driven. If the events don’t occur that year, the accumulated damage may be less than predicted and *vise versa*. From a riser IM perspective, what matters is that the accumulated damage to date plus the estimated damage in the future does not exceed Equation (35). Damage is what is calculated, and what is accrued

during the actual service of the riser. Life is just a word that helps explain the situation to a stakeholder. If one asks the question, "What is the fatigue life of this riser?" at the end of design, before installation, the answer is the inverse of the left-hand side of Equation (35). If one asks the same question after 10 years of service, it can have many answers and hence is not a useful question. The useful question is to ask about remaining life until the allowable damage is reached, based on the damage already accrued plus the predicted damage going forward, but this is not "fatigue life". It is "remaining fatigue life".

3) Disconnect between FPS life and riser life – Risers are often installed at intervals after the FPS is installed. Stakeholders tend to focus on the life of the FPS, and sometimes implicitly assume the "fatigue life" of a riser began on the same day as the FPS, when in reality, it could be anywhere from months to years to decades thereafter. Consistently referring to fatigue in terms of predicted damage vs allowable damage is the preferred and least confusing way of addressing fatigue, with "remaining life" being a summary term that refers to the predicted time until the allowable damage is reached. This is only the same as "fatigue life" prior to riser installation, and hence should be avoided.

EXAMPLE – A High Safety Category subsea production SCR is designed for a 20-year service life. SCRs are not retrievable, so F_{Fat} = 10, and the corresponding allowable damage over the service life is 0.10 (Equation (35)). After completing all analysis and finalizing the design of the riser, the calculated damage over 20 years of service, comes to 0.09. This corresponds to an annual damage accumulation rate of 0.09 / 20 = 0.0045 per year. The fatigue life of this riser is 0.10 / 0.0045 = 22.2 years, so one can say that it has a "fatigue life of 22.2 years".

However, one of the sources of fatigue is VIV during sustained current events that are episodic – i.e., they either occur or they do not occur; they are not continuously present. In the first 10 years of service, the riser does not see any of these episodic events. The Operator has implemented a robust IM plan following API RP 2RIM. Through monitoring of platform motions and met-ocean conditions, the Operator keeps track of the damage incurred and through a re-assessment, determines that the damage accrued at the end of year 10 is 0.035.

The Operator is considering extending the life of the riser beyond the original 20 years and wants to know the remaining fatigue life to make an economic evaluation of future scenarios. The predicted damage in 10 years in the original design was 0.045, leaving 0.055 yet to be consumed, which as calculated above, corresponds to 12.2 years remaining life at the end of year 10.

However, the actual damage incurred was less, leaving 0.10 – 0.035 = 0.065 damage yet to be consumed. There have been no changes in the condition of the riser or the FPS that affect fatigue so the projected fatigue damage going forward remains the same as the original design at 0.0045 per year. This translates to a remaining fatigue life of 0.065 / 0.0045 = 14.4 years. At this point, one can say to stakeholders that the riser has 14.4 years remaining life from the end of year 10 if the future conditions remain the same as in the original design basis.

This becomes even more complicated if the riser was installed 2-1/2 years after the FPS, in which case the riser's original design "fatigue life" of 22.2 years give it a good-to date of 24.7 years after FPS installation, creating addition potential for confusion.

For a variety of logistical reasons, the report detailing this re-assessment is finally completed and approved around the start of year 12. The Asset Manager reads the report prior to the next IM review in the middle of year 12, so when he sees 14.4 years remaining life, the manager assumes this is from the date of the report, rather than the end of year 10, and is further confused because he also has a FPS fatigue IM report that refers to year 12 and 13. The best practice is to not refer to remaining life directly but rather convert the remaining life to a specific date. This is the information the stakeholder needed in the first place, and as such operations stakeholders are not likely to be riser fatigue experts, the details beyond that are best left to the detailed technical report reviewed by technical assurance experts.

Non-permanent riser components:

Non-permanent riser components as described in 5.6.4 are primarily associated with FPS drilling risers that can be retrieved in their entirety between wells. Certain riser tensioner components could be considered non-permanent if they can be readily removed and replaced from the FPS topsides, and the riser load cases include one tensioner cylinder missing with an appropriate storm commensurate with the time it takes to remove and replace the cylinder.

Production risers should be considered permanent. Although in principle, any top-tensioned riser can be retrieved, planning to retrieve it at a regular interval would require shut-in and substantial costs in terms of deferred production, as well as the plugging and abandoning the well.

There are situations where a permanent TTR is retrieved for reasons not related to integrity management, such as the need to sidetrack the well with a drilling riser, or abandonment of the well and re-use of the riser on another well, but these are not events that can be anticipated at the time of design. In other words, the Operator cannot plan for regular dry inspections like a drilling riser. Hence TTRs other than drilling risers should be considered permanent even if they can be retrieved and re-installed. However, any retrieval is a good opportunity for pro-active inspection as prescribed for non-permanent risers.

A.5.6.5 – Single Event Fatigue

The intent of the single event fatigue design requirement is to ensure that the design is not susceptible to nonlinear or accelerated fatigue damage accumulation when subjected to larger stress cycles than are represented in the long-term fatigue analysis – i.e., sustained low-cycle, high-stress fatigue from an Extreme/ULS or Survival/ALS event. While the long-term fatigue design considers large amplitude events like extreme hurricanes or loop currents, they are discounted by their low probability of occurrence in the long-term analysis because they are statistically very rare and hence are under-represented – i.e., risers have design lives of 20 to 30 years whereas the Extreme/ULS and Survival/ALS events have much lower probabilities of occurrence. However, if such an event occurs, the accumulated fatigue damage could be high. These design checks are to ensure the Extreme/ULS event does not consume the riser fatigue design margin, and that the Survival/ALS case does not lead to catastrophic failure.

From the design perspective, the assessments of long-term fatigue damage rates using the scatter diagram and short-term (single event) fatigue damage rates are independent. Both long-term and single event fatigue damage rates are required to meet their individual design criteria and should not be combined when assessing each criterion.

This approach is analogous to the ECA approach, which combines the long-term and short-term fatigue by comparing the final flaw size at the end of life due to the long-term fatigue to the allowable flaw size for a single extreme event, with the allowable flaw size controlled by the maximum longitudinal stress corresponding to the single extreme event.

Since a safety factor of 10 is specified for long-term and single-event fatigue (ULS, all risers), and the S-N fatigue method is required, there is no expectation that, should a riser accumulate its full 0.1 scatter diagram fatigue, and sustain an Extreme/ULS event, it will fail for the rare case when a single extreme event happens at the end of the service life. There remains a substantial safety margin of 0.8 damage (i.e., what is left when 0.1 is consumed by both long-term and single-event fatigue).

If the riser's fatigue behavior is linear with increased loading, this should not present any problems passing the single-event design criteria. However, the single event design criteria will highlight designs that have abrupt changes in fatigue behavior and may lead to design changes.

> EXAMPLE 1 – VIV can cause significant fatigue damage during the design life. If the design does not include adequate suppression for the higher currents expected in Extreme/ULS and Survival/ALS events, the VIV damage could increase dramatically in the single event fatigue assessment.

EXAMPLE 2 – Threaded connector designs are sensitive to dynamic loads as the threads come in and out of contact with one another. One way to address this is to build-in pre-tension so that the threads remain in contact. The S-N curve for the connector may change slope significantly if the pre-tension is fully removed in a high-load situation. Should this occur in extreme environmental events, the fatigue damage could be substantial.

Mechanical connectors (preloaded or not) are characterized by a nonlinear stress transfer function between nominal pipe stress and the local stress in the connector/threads. Such stress transfer function should be obtained from detailed FEA and used in the SCF/SAF or direct fatigue calculation. Alternatively, the conservative constant equivalent SCF/SAF can be obtained from full-scale testing. Refer to API Std 17G for additional guidance on the fatigue evaluation of mechanical connectors.

EXAMPLE 3 – Top-tensioned risers rely on tensioners to maintain relatively constant tension. If the tensioner strokes out to the limit, the behavior quickly changes as the top of the riser will now move directly with the FPS, greatly increasing stress temporarily until the load reverses. This could increase fatigue damage substantially in high-load events.

A.5.6.6 – Engineering Criticality Assessment (ECA)

The reliable detection of cracks in non-permanent components (e.g., drilling risers) can be done onshore using proven inspection methods. Reliable crack detection for in-situ riser components is a technological challenge that, at the time of publication of this recommended practice, is not practical.

A.5.7 Interference

DNV-RP-F203 provides useful guidance on how to calculate clearances and what effects should be considered in performing interference analysis.

The interference analysis should be performed to ascertain whether clashing could occur between a riser and any object sufficiently close to it. The general principles for assigning load case categories for interference are the same as for strength load cases (Section 4). The interference load case table should be developed with combinations of current velocities, current directions, critical riser pair with loading conditions, FPS offsets, and FPS dynamic motions.

The riser interference analysis should be performed for all types of current profiles provided by the metocean data.

It is typical that initial screening is conducted for currents from all directions, possibly without host offset or host dynamic motion, to define the most critical directions where interference might occur. These directions should be further analyzed with full host offset and host dynamic motions. Screening should be a bit conservative with potential interference cases further refined through sensitivity studies for host offset and current directionality variations.

Note that the results obtained from interference analysis are highly dependent on the analysis approach and design parameters selected. Some important parameters are listed below. Further guidance on the appropriate selection of these parameters can be found in DNV-RP-F203.

- Static versus dynamic analyses
- Marine growth assumptions
- Shielding effects resulting in reduced mean drag forces on downstream risers
- Lift forces on the downstream riser due to velocity gradients in the wake field
- VIV drag amplification factors

The highest risk of interference is generally associated with the ULS and ALS events that include large lateral excursions as well as large motions. However, some FPSs are designed with active mooring systems used to position the FPS over nearby wells that might create potential interference situations during SLS events. Similarly, TTR tensioner systems are sometimes adjusted during operations and returned to their design tension for ULS or ALS events. Situations such as these should also be considered in developing the load cases for interference checks.

Table 8

While only Category A specifies a minimum clearance, it is prudent to include a minimum clearance for Categories B and C as well, at least during the design phase, to account for design changes in other areas such as mooring system stiffness of other FPS changes resulting in greater offsets of motions, operational mooring line adjustments for FPSs with drilling rigs, etc. Adjacent risers with significantly different diameters or weight are typically more susceptible to interference. For SCRs, typical mitigations include varying departure angles for adjacent risers. Azimuth angles differences between adjacent risers can also reduce the risk of interference provided this can be accommodated by the seafloor flowline layout.

Note 1 clarifies that the diameter used in determining clearances should include anything that affects riser integrity such as buoyancy, insulation or VIV suppression devices. If damage to these appurtenances do not affect riser integrity (i.e., the riser can pass all of the design requirements with the anticipated damage), then those appurtenances need not be included in the clearance. It is up to the designer to assess the potential for damage and the impact on the design should it occur.

> EXAMPLE Most risers are designed with more VIV suppression than required to meet the fatigue requirements. VIV suppression is easily damaged during installation and in-service, and replacing it in-situ is much more costly than adding extra suppression during riser installation. Hence, a local clash would only damage a small segment of suppression. This requirement is more intended to protect against a situation where two risers have the potential to rub over a long length of riser where enough suppression could be damaged or lost to significantly change the VIV fatigue damage estimates.

Table 9 – Riser Interference Categories for Different Environments

The criteria specified in Table 9 distinguishes between storm events and current events. These are generally the same environmental events used in the design of the riser as described in Section 4.

Storm events are short in duration and the riser response is dominated by the dynamic wave action. Storms have an associated current, but the waves will usually have the controlling effect. Examples include winter storms, hurricanes and squalls.

Current events are based on currents not generated by storms and may have a much longer duration at peak strength. These are generally related to oceanic circulation currents such as the Gulf Stream in the North Atlantic and its incursions into the Gulf of Mexico referred to as the Loop Current. Current events will have associated waves due to a correlated storm event associated with the joint probability of the oceanic current and local storms for a given probability of exceedance (i.e., return period) but the riser response will be dominated by the quasi-static current loads.

A.6 Design Criteria for Components

A.6.1 Riser Component Design and Verification

Critical Regions

Critical regions of risers are areas of high static and dynamic loading, particularly where moment is transferred to supporting structures or the seabed. Usually, any transition point in geometry is a critical region as far as stress is concerned.

Critical regions of TTRs include components that transition from unrestrained center riser tubes to rigid end connections. These regions are typically exposed to the highest bending, tension, and compression loads, and may have the most fatigue damage. Specialty joints are typically deployed in critical regions to handle the loads and strokes determined by the global riser analysis. Specialty joints include components that interface with the FPS (e.g., tensioner joints, splash zone joints, centralizer joints, keel joints, stress joints, telescopic joints, flexible joints, ball joints) as well as stress joints at the riser base. Riser configurations may include one or several of these specialty joints.

Critical regions of SCRs include the top of the riser where it is supported (i.e., specialty joints such as tapered stress joints, flexible joints, or cantilevered pull tubes) and the touchdown area where it transitions to seabed support. Critical regions could also include buoyancy hog/sag bends and buoyancy attachment points for lazy-wave SCRs depending on the configuration.

Hybrid risers are a combination of flexible riser and TTR riser components. Critical regions of hybrid risers are found at transition points, which are typically similar to TTR and flexible regions listed above.

Components in critical regions should be carefully considered during design verification. Specialty joints should be appropriately modeled in the global riser analysis and may require modeling of these specialty joints and their interfaces with hull using nonlinear elements to account for contacting and sliding loads. For the keel joint and keel guide interfaces, contact elements with sliding capability will need to be used to capture strength and fatigue loads accurately for the code check of these specialty joints. The interface loads captured in the global riser analysis should be provided to the hull and riser component design teams for the backup structural design. Component analysis of specialty joints is required to assess the strength and fatigue performance utilizing loads obtained from the global riser analysis. Detailed geometry needs to be adequately modelled in the component analysis to capture stress concentrations. The component analysis should also assess the separation characteristics of preloaded components.

Safeguards

Recommended safeguards to ensure a safe and robust riser design include leak-before-break and tubular exceedance methodologies. These methodologies have been used for decades and are accepted practices during tubular sizing and the design of riser components.

Tubular exceedance refers to the practice of designing riser load bearing components to have a greater load capacity than the tubular (e.g., riser pipe). Riser pipe sections are typically of far greater length than the components that connect them and made of materials that demonstrate high ductility. During an overload event, these pipes will exhibit significant plastic stretch. This stretch provides both a warning that the riser system is being overloaded as well as tolerance to the vessel being out of the positional envelope that it was designed for, without the riser system failing catastrophically. Riser couplings, riser connectors, and other specialty joints typically adhere to this practice and are proven to produce outlasting component designs when assessed for both design event and service life criteria.

TTR Support

The global riser analysis should be used to determine the riser tension requirements for TTRs with the riser tension typically applied by a passive hydro-pneumatic tensioner system.

The riser tensioner design may be an iterative process. Initial tensioner modelling is input into the global riser analysis to determine the required nominal tension, the allowable bounds for tensioner stiffness or spring rate, and the overall range of up-stroke and down-stroke. These values are supplied to the

tensioner system designer who develops the tensioner performance curve (typically non-linear), which is then inserted into the global riser analysis for verification of the riser design in normal, extreme and survival conditions. An appropriate polytropic constant should be used to best represent the practical performance of the system while in service. The tensioner stroke capacity should be designed according to the simulation results to avoid tensioner top out or bottom out. The amount of top tension applied to a TTR not only affects its global strength and fatigue performance but may also have impact on the vessel payload and vessel's global performance. Vessel payload should be computed using a coupled hull, mooring, and riser model.

One alternative to a hydro-pneumatic tensioner system is buoyancy cans or air cans secured to the riser that displace large volumes of seawater (i.e., buoyancy) to provide riser tension without transferring the load to the hull. For a buoyancy can supported TTR, the interaction of the buoyancy can with the hull supports that guide the buoyancy can as it moves parallel to the hull should be captured to ensure that the structural integrity, strength and fatigue, of the buoyancy can and the hull structures are adequate.

SCR Support

SCRs are typically supported by a riser support structure (i.e., riser porch), which requires either a tapered stress joint to absorb the moment at the top of the riser, or a flexible joint to allow for the SCR top hang off to move through a range of angles to account for FPS motions. The flexible joint or the stress joint need to be designed so that the SCR will not come in contact with hull structure and help maintaining the structural integrity of both SCR and the hull hang off structures. The design process of SCR hang off is an iterative process that starts from the initial rotational stiffness data of the flexible joint, or the size limit of the stress joint provided by the suppliers. The reaction loads from the riser analysis should be provided to the supplier for their detail design of the flexible joint or stress joint. The pertinent detailed design information for the flexible joint or the stress joint should be included in the riser global model for the strength and fatigue check of the SCR and hull hang off structure. For stress joints, this is primarily the geometry of the stress joint. For flexible joints, this includes primarily the nonlinear stiffness curves, as well as the extension forging geometry.

Flexible Joints

Flexible joints are sometimes used to support the riser at the FPS. Flexible joints allow the riser to rotate through small angles at the hang-off point, greatly reducing the moment transmitted to the FPS structure. The flexible joint allows a discontinuity in slope on either side of the center of rotation. Typically, one end is fixed while the other end is allowed to rotate through the use of steel shims and elastomeric materials in between.

The rotation angle requirements and design characteristics should be determined from global riser analysis. The flexible joint system rotational stiffness (moment variation versus angle change), including any nonlinear and hysteretic behaviors, should be accurately reflected in the global riser analysis. The temperature rating of the flexible joint will influence the rotational stiffness and should be verified that the rating is consistent with operation temperatures. Verification of the flexible joint design should satisfy all load combination and fatigue design criteria per Section 6.

Tapered Stress Joints

Tapered stress joints are frequently used to support SCRs. Instead of absorbing the moment at the top of the riser by rotation like a flexible joint, a tapered stress joint transfers the moment to the riser support structure and into the FPS hull structure. For smaller riser, this is relatively easy within typical riser support structure designs. For larger risers, this can become quite challenging. Refer to Gordon & Dareing (2004) [A22] for general guidance on the design of tapered stress joints.

Specialty Joints

The design of specialty joints usually involve irregular profiles to accommodate mechanical attachments or create a high bending resistance feature. It is advised not to account for external pressure in these features when determining burst capacity.

Tie-back Connectors

TTRs are attached to the subsea wellhead or riser base by a tie-back connector (TBC). The TBC is a mechanical or hydraulic connector that latches to a profile on a subsea wellhead and provides a seal between the riser bore and the environment. The TBC should have a position indicator to allow visual verification of locking mechanism. Hydraulic connectors should be designed to remain locked upon loss of pressure in the lock port and should include primary and secondary unlocking functionality. The TBC may be integral to the stress joint or bolted on.

For a dual casing TTR, an internal tieback connector (ITBC) is required to latch the inner riser to the subsea wellhead or the stress joint and to provide a bi-directional seal. Typically, the annulus side of the seal is not exposed to wellbore fluid, and it may have a lower pressure rating than the bore seal. The ITBC is typically a mechanical connector that is retrievable. Torque is used to activate the seal or to retrieve the ITBC. The design should ensure that the torque require to preload/retrieve the ITBC stays within the torque limitations of any threaded riser connectors used on the inner riser joints. The ITBC latch mechanism should be a robust design that allows the connector to be made up and retrieved. There should be a method of verifying the ITBC is fully engaged prior to performing a pressure test. The ITBC should be designed to withstand tension, compression and bending loads in addition to internal and external pressure. The riser design can greatly impact the external loads applied to the ITBC, so it is critical that the driving load cases are provided to the ITBC designer.

A.6.2 Fatigue

Component design should exhibit features that contain smooth transitions with chamfered or rounded edges. Sharp root radii should be avoided in threaded features and appropriate tooling be utilized to achieve smooth transitions where possible. Connections with preload are desired to achieve improved fatigue performance. The preload magnitude should be specified relative to normal or operating riser loads.

The S-N approach is the industry standard practice for riser fatigue design and life extension. Typically, a single S-N curve is applied to all stages of the fatigue life of a component, and the fatigue failure point is defined as through-thickness crack. S-N curves are based on mechanical testing of material starting from a pristine, crack-free condition, including the crack initiation and crack propagation phases.

A fracture mechanics assessment or engineering criticality assessment (ECA) provides a supplemental or alternative method for in-service component fatigue re-assessment, and for life extension evaluation. It can substantially improve the reliability of fracture or fatigue critical welds by establishing technical bases for NDE system qualifications, weld flaw acceptance criteria (7.12.4), and specified weld toughness requirements (7.8.2). A fracture mechanics assessment is based on a linear-elastic fracture mechanics model, which focuses on crack-like flaw propagation and end-of-life fracture. As a refined approach, the fracture mechanics assessment predicts the fatigue life by evaluating the crack growth as function of stress cycles, structural and crack geometry, material parameters, weld qualities, and operating environments. With good data collection and management, a fracture mechanics assessment can be used as a more refined tool to predict remaining life of riser components. Fracture mechanics is not an appropriate tool for fatigue reassessment if the requisite fabrication and in-service data is not available. Refer to API RP 2RIM for guidance on integrity management of risers.

Refer to BS 7910 for detailed guidance on fatigue assessment using fracture mechanics. Refer to Ziegler & Muskulus (2016) [A20] for a comparison of S-N vs ECA.

Conducting a Fracture Mechanics Assessment

Along the riser length, the components identified at the critical weld locations for fatigue using the S-N approach should be included in the fracture mechanics assessment. For SCRs, critical locations typically include the touch-down and hang-off areas. OD surface breaking flaws, ID surface breaking flaws, and buried flaws are considered for different environments (e.g., in seawater with cathodic protection, in air, in presence of sour service, etc). The flaw growth evaluation is based on the fatigue crack growth rate corresponding to different environments.

The facture mechanics assessment considers the post-weld processing (i.e., ground flush at the weld cap and root) for different installation methods with the application of appropriate magnification factors. Other weld geometry data, including Hi-Low values and pipe-end thickness tolerances, should be used for stress concentration factor calculation.

The fracture toughness measured in terms of crack tip opening displacement (CTOD) testing is essential for the facture mechanics assessment, which may also be estimated from relevant Charpy V-notch data.

The fracture mechanics approach assumes that the crack growth increment per load cycle follows an exponential function with stress intensity factor and the material parameters. The weld and material properties are provided for the parameter calculation. The riser global strength and fatigue analysis provides the fracture and fatigue loading. The maximum longitudinal stresses at pipe OD and ID at the critical locations obtained from riser global strength analysis are used as inputs to generate the primary membrane and primary bending stresses for performing fracture check. The stress ranges due to fatigue loading obtained from the riser global fatigue analysis are used to calculate the fatigue flaw growth.

In a typical fracture mechanics assessment design case, the initial flaw sizes are assessed to grow into the final flaw sizes after applying long-term fatigue loading with a safety factor of 5 applied on design life, which should be less than the allowable flaw size (fracture analysis) due to maximum longitudinal stress corresponding to the extreme/ULS 100-year storm condition.

A.7 Materials

A.7.4 Other Materials

A.7.4.2 Titanium

Strength and fracture properties in Grade 23/29 titanium are not derived from tempering and aging treatments. Strength in these alloys instead stems primarily from a combination of substitutional alloying (i.e., Al and V additions) and interstitial (O, N) strengthening. These components are processed to achieve a stress relieved, thermally stable two phase (alpha-beta) structure involving a fully transformed-beta (acicular-alpha) microstructure which provides maximum fracture resistance for this metallurgy with a small sacrifice in yield strength (compared to traditional Grade 5 microstructures used in aerospace). Along with a very high degree of chemical homogeneity and relatively consistent grain size, this titanium alloy metallurgy results in minimal property directionality (i.e., near isotropic) and low property variation through the component's cross section.

The NDE approach commonly adopted for titanium is different than for steel components. All of the usual NDE for non-magnetic materials apply and are used: PAUT (including FMC, TFM, IWEX, etc), RT, PT, ET, and VT. Specific to UT, titanium does not pass sound as readily as steel. Hence, for thicker sections the wall thickness is broken into zones, each with a specific criteria from ASTM E2375 [S20], the tightest being Class AA, the OD zone.

Mitigating galvanic dissimilarities

Buffers can be dielectric or non-metallic, and can be conductive or non-conductive. For example, Inconel 625 is a conductive metallic buffer material used between titanium and steel flange connections.

Shielding must be non-metallic and non-conductive. Examples of shielding include rubber sheet coatings (per ISO 18797 [S38]) or cast polyurethane (PU) coatings (per ISO 12736 [S39]) used between titanium (or steel) and seawater.

Isolation can be metallic or non-metallic, but must be non-conductive. For example, a non-conductive composite isolation sleeve might be used between titanium and the riser porch for a tapered stress joint.

There is a distinction between shielding and isolation. A galvanic cell requires three items: anode (steel), cathode (titanium), and electrolyte (seawater). *Shielding* is used to break the link from the electrolyte (seawater) to the anode (steel) or cathode (titanium). *Isolation* is used to break the link between dissimilar metals, separating the anode (steel) from the cathode (titanium)

> EXAMPLE: A carbon steel SCR is terminated with a titanium stress joint. The galvanic dissimilarities created by the inclusion of the titanium component in a submerged carbon steel riser and riser porch system are managed as follows. The titanium is directly connected to the steel topside piping above and riser pipe below, using conductive Inconel 625 buffers. The external titanium surfaces are shielded from seawater (electrolyte) with non-conductive coatings such as rubber or polyurethane. The stress joint hang-off location is isolated from the FPS riser porch with a non-conductive isolation barrier to prevent CP drain back into the FPS hull. The flange studs and nuts are isolated from the conductive flange metals to prevent CP charging.

A.7.4.3 Composites

For additional guidance on composite materials, refer to DNV-ST-C501 [S28] and DNV-ST-F119.

A.7.5 Requirements for elevated temperature

Steel/metal strength decreases progressively above a certain elevated temperature. The strength corresponding to the elevated temperature should be used in each load case. This strength can best be determined by tensile testing at the elevated temperature. However, typically, this would not be possible during the design phase which preceded ordering the pipe.

Absent test data, the methodology used for temperature de-rating for elevated temperatures should be consistent with that used for the design of the pipeline such as ASME B31.8, DNV-ST-F101 or another recognized equivalent. Test data from the pipe mill or prior projects for pipe of similar material composition may also be used and verified later by tensile testing after the pipe becomes available.

The derating approach differs between codes; the methodology used for temperature de-material strength rating for elevated temperatures should be consistent with the standards used for the design of the pipeline.

A.7.9 Corrosion Mitigation

Selection of external coating systems can include consideration of the following:

a) mechanical loading, including hydrostatic pressure, thermal expansion (or contraction), handling/installation loads, fatigue loads, damage due to make-up and break-out of threaded connectors, and wear against other components;

b) resistance to damage from temporary exposure to internal fluids during make-up or break-out of threaded connectors;

c) resistance to under-film corrosion, dis-bonding, cold flow, embrittlement, chalking and cracking;

d) resistance to galvanic corrosion where dissimilar materials are joined;

e) enhanced protection under strakes and fairings where CP might not be as effective;

f) enhanced protection in the splash zone where CP is not as effective;

g) maintenance, repair and/or reapplication;

h) routine preservation;

i) passive fire protection.

A.7.10 Structural Riser Components

Structural riser components are defined as components that are not pressurized or welded to pressurized riser components. Some examples of structural riser components are buoyancy cans, tensioners, porches, pull tubes, etc.

Structural riser components should satisfy the requirements of specified material standards, such as ASTM A36/A36M [S17], ASTM A516/A516M [S18] and ASTM A537/A537M [S19], and API Spec 2H [S09], API Spec 2W [S13] and API Spec 2Y [S14].

Fabrication of structural riser components should be consistent with specified structural design codes, such as API 2A-WSD [S08].

Welding of structural riser components should be consistent with specified structural welding codes, such as AWS D1.1/D1.1M [S21].

Tensioner accumulators and cylinders are often designed to ASME Section VIII Div 1 & Div 2.

A.7.11 Manufacture, Welding, and Fabrication

A.7.11.11

Other types of CRA linings such as mechanically-lined pipe should only be considered after substantial qualification testing.

A.8 Fabrication and Installation

A.8.3 Transportation, Shipping, and Installation

A.8.3.2.2 Risk Assessment

Additional guidance for performing risk assessment for marine and subsea operations can be found in ISO 17776 [S30] and DNV-RP-N101 [S27].

A.8.3.4 Installation Procedures

TTR Tubular Installation Procedure - Tension Distribution

For risers with multiple tubulars where the tension distribution between tubulars can be controlled during installation using relative pretension, the effective tension in all tubulars should be maximized across the load conditions. This is particularly true for normal operating conditions that the riser is expected to experience for long durations and for primary structural tubular (typically the outer riser of a TTR). It is often not possible to maintain effective tension in all tubulars for all load conditions while maintaining reasonable top tension. For cases where a tubular is compressed, but stability of the riser system is maintained by tension in the other tubulars, it is important to ensure that the centralizer location and numbers are sufficient to control the tubular shape and the strength and fatigue performance of each tubular, mechanical connection, and centralizer is acceptable.

The density and corrosion inhibition should be maintained as per design to ensure tension distribution and integrity of the inner strings of the riser for the life of the well.

A.8.3.4.2 Towing

Additional guidance pertaining to installation by towing, refer to DNV-OS-F101.

A.8.3.4.3 Reeling

For guidance pertaining to installation by reeling, refer to DNV-OS-F101.

A.8.3.4.4 S or J Lay

Preparation of multiple joints (hex joints, quad joints, etc) encompasses activities that may be performed either onshore or offshore.

The selection of S-lay or J-lay for the installation of SCRs will depend on the balances of the construction speed (S-lay's multiple firing lines), installation vessel's tensioner capacities, and the performance of the SCR during the riser installation process".

A.8.3.5.4 SCR Configuration

The establishment of the precise location of the riser touch down point may be hard to determine due to sea floor condition. For this reason, it is common to establish a work point further along the riser on the static portion lying on the seafloor.

A.9 Riser Integrity Management

A.9.1 Integrity Management Plan

As stated clearly in API RP 2RIM, proper IM begins in the design phase. Problems with IM, and in particular with life extension (LE), can often be attributed to lack of proper documentation of the design or retention of data from construction, and baseline inspections just after installation (i.e., as-built conditions). These activities should be integral to the project execution plan for designing and constructing riser systems to ensure good IM practices going forward.

Most operators have standard riser inspection and monitoring procedures. However, each riser system has its own unique design and construction data, and some riser systems have unique features that require specific operating, maintenance, inspection, or monitoring requirements that should be clearly documented for the operator.

The operator should be engaged at all stages of design and construction around IM activities and requirements so that the operator can provide input and feedback on any unique features and can ensure the operator's IM requirements can be met once the riser system is in operation. There should not be any surprises for the operator after hand-over in terms of IM requirements.

Many national regulatory bodies have specific requirements for IM activities. These can be in the form of minimum requirements for documentation of risk and risk management measures such as which documents are to be presented to the authorities and mandatory use of specific standards. The authorities can also have requirements for IM activities, such as roles and responsibilities, content and form of verification activities, terminology, minimum inspection scope, periodicity of inspections, and condition monitoring.

A.9.2 Re-assessment of Existing Risers

A.9.2.1 General

Depending on the re-assessment trigger, the load cases that are relevant to the re-assessment may be less than the full complement from the original design (Section 4). However, the starting point should be to look at all load cases from the original design and the most recent re-assessments. If it can be shown without re-analysis that the trigger has no impact on those load cases, then there is no need to repeat analysis that will clearly have the same input and output.

It may be appropriate to perform the re-assessment as per the latest editions of the same codes/standards used in the original design.

Where allowed in the Normative, reliability-based assessment may be used for fatigue as described in DNV-ST-F204 [S26] and DNV-ST-F201 [S29] with probability of failures calculations and subsequent case specific risk assessments, as applicable based on characteristic data collected in the field, during operation and/or installation and construction. This applies only to the methodologies. Like API RP 2RD, DNV-ST-F204 [S26] and DNV-ST-F201 [S29] are part of an over-arching design philosophy in conjunction with other DNV pipeline and riser codes, and care should be taken in cherry-picking aspects of DNV standards. The endorsement of DNV here is for the reliability-based assessment methodology, not other design criteria or safety factors.

EXAMPLE 1 – If the trigger for re-assessment is more corrosion wall loss than anticipated, then governing load cases should be included in the re-analysis.

EXAMPLE 2 – A riser was designed for a specific chemical environment and historical production data shows that the actual environment (e.g., designed for H_2S but H_2S was never present) was different than designed. An assessment can be performed to re-assess the fatigue performance utilizing appropriate fatigue curves based on the actual environment.

EXAMPLE 3 – The VIV suppression on a riser has been periodically ineffective due to the presence of marine growth or loss of suppression. The durations of VIV effectiveness should be evaluated based on inspection data and utilized in a re-assessment. See related example in API RP 2RIM.

EXAMPLE 4 – A production TTR was installed in 2010 using API RP 2RD First Edition [S11]. It was installed on a Spar using a buoyancy can for maintaining top tension. During the installation of the riser, unanticipated circumstances led to the available riser stroke being a meter less than specified in the design, and outside of installation tolerances considered in the design. The as-built analysis shows compliance with first edition criteria, which does not include a 1,000-year return period event. Years later, a trigger occurs (e.g., life extension) that requires re-assessment of the riser to the present edition. The analysis for the Survival/ALS case shows the buoyancy can contacts the stops during the 1,000-year Survival/ALS event, resulting in unacceptable stresses for the criteria given in Section 5 and Section 6.

EXAMPLE 5 – A production TTR is designed to this Recommended Practice and installation results in a similar out of tolerance on available stroke. In this case, sub-section 9.2 does not apply. If the as-built analysis shows it does not comply with Section 5 and Section 6, then a risk assessment should be performed to define appropriate mitigations such that the riser is deemed safe to operate for any well completion activities.

A.9.2.2 Alternative Requirements for Survival/ALS Strength Load Cases

As discussed elsewhere in this Annex (A.4), the purpose of the Survival/ALS load case is to demonstrate robustness and to guard against failure modes that have abrupt changes in behavior with increasing load. The requirements of Section 5 around Survival/ALS load cases are intended to exclude safe risers designed to earlier codes, and these alternative requirements should adequately address these situations while maintaining a level of demonstrated robustness.

There are two main reasons for including these re-assessment exceptions for Survival/ALS acceptance criteria for re-assessment of risers designed to previous editions [S11, S12] of this Recommended Practice.

- Less stringent Survival/ALS criteria in earlier codes – In the two previous editions, the Survival/ALS strength load cases were not well defined. The first edition [S11] simply stated that "the designer should evaluate response to survival conditions that exceed the extreme design events", so effectively there was no specific criteria on the load side or response side. The second edition [S12] provided specific acceptance criteria, but it allowed anything from 100-year to 1,000-year return period for the environmental event without any guidance on justifying the selection. Hence, some risers designed to these earlier editions might not pass the 1,000-year Survival/ALS criteria in this edition. Since both previous editions are accepted to produce safe designs, this exception allows alternate means of demonstrating the design is robust.

- Increase in met-ocean criteria – This is specifically intended to address risers designed and installed in the Gulf of Mexico prior to 2007. After the extreme hurricanes of 2004 and 2005 [A23, A24], the metocean criteria for the Gulf of Mexico increased substantially, as much as 20% in some areas. In 2007, API published three interim standards to provide interim guidance for updated metocean criteria, design of new systems going forward, and re-assessment of existing systems –

    a. API BULLETIN 2INT-MET [S31] for new metocean criteria,
    b. API BULLETIN 2INT-DG [S32] for the design of new offshore platforms (including risers)
    c. API BULLETIN 2INT-EX [S33] for the assessment of existing offshore platforms (including risers)

    These standards were eventually withdrawn when the associated API design standards were updated to address these situations.

    In 2007, the US regulator issued NTL-2007-G27 [A25] requiring all existing offshore installations, including risers, to be re-assessed in accordance with API BULLETIN 2INT-EX [S33], using metocean criteria from API BULLETIN 2INT-MET [S31] (since superseded by API RP 2MET [S10]). This included an equivalent Survival/ALS check (referred to as a robustness check in API BULLETIN 2INT-EX [S33]) that recommended a 1,000-year return period but accepted as low as a 200-year return period. This was considered by API and the regulator to be a safe practice under the circumstances for those risers already installed, but did not endorse this practice for risers designed thereafter, which is addressed in API BULLETIN 2INT-DG [S32] and subsequently API STD 2RD (Second Edition) [S12]. Hence, the current edition of this Recommended Practice should not retroactively exclude those risers as safe from a strength design perspective so long as the risers have been maintained properly. However, this does not

apply to risers designed to the metocean criteria developed subsequently per API BULLETIN 2INT-MET [S31] or API RP 2MET [S10].

In the Gulf of Mexico, the Survival/ALS event is generally a hurricane, for which personnel are evacuated from the FPS, and hence there is no risk to people. By isolating risers from the hydrocarbon source, such that failure will not likely lead to a substantial release can prevent escalation in many cases, as can demonstrating that ultimate failure would occur without harm to other systems or with significant release of hydrocarbons.

If a Survival/ALS load case return period is less than the original design, mitigations should be considered to reduce the potential consequences of catastrophic failure. The risk assessment and mitigations should focus on personal safety and environmental pollution.

Examples of possible mitigations include:

- Personal safety risk is reduced if the FPS is unmanned during the Survival/ALS event.
- Environmental pollution risk is reduced if the riser is either Low safety class (5.1) or blown down prior to the Survival/ALS event.
- If the riser is connected to a well, ensuring one or more safety valves that isolates the riser from any pressurized hydrocarbon source (e.g., subsea safety valve, subsea tree isolation valve, subsurface safety valve).
- If the riser is connected to an export line and there is a subsea isolation valve that can be closed, the volume of any potential environmental release is capped.

Examples of application of alternative requirements –

EXAMPLE 6 – A riser is designed for a Survival/ALS return period of 1,000 years, corresponding to a 20 meter significant wave height. Some years later, the metocean conditions are determined to have increased. The new 1,000-year significant wave height is 22 meters. The new 200-year significant wave height is 18 meters. While the new metocean conditions must be used for the Operating/SLS and Extreme/ULS load cases, the Survival/ALS case may remain at 20 meters because it is still greater than the new 200-year return period event.

EXAMPLE 7 – A riser was designed and installed in 2017 to API Standard 2RD, Second Edition [S12], which required an ALS load case with a return period between 100 and 1,000 years for the original design. A 500-year return period was selected for the ALS case in the design with a significant wave height of 18 meters. There has been no change in metocean criteria. Hence, the re-assessment may be made using the same 500-year return period event. This is greater than the minimum 200-year return period.

EXAMPLE 8 – A riser was designed and installed in the Gulf of Mexico in 2002 using API RP 2RD, First Edition [S11], which did not have a specific requirement for the Survival load case return period except that it be longer than the Extreme load case. The original design used a Survival seastate with a 200-year return period with a significant wave height of 13 meters. However, in the intervening time, the metocean conditions rose substantially after the extreme hurricanes of 2004 and 2005. The riser was re-assessed in 2007 based on API BULLETIN 2INT-EX to a revised metocean criteria with a 200-year return period with a significant wave height of 16 meters. Years later, it is re-assessed again per this Recommended Practice. The metocean conditions have not changed in the intervening time so the re-assessment can be made for the 16 meter significant wave height 200-year return period Survival/ALS event.

A.9.2.3 Fatigue Re-assessment of Existing Risers

The reduction of uncertainty around past environmental events can be used to justify a reduction in fatigue safety factor for damage that has occurred in the past. This can be used routinely in the IM

program to keep track of how much fatigue life remains, and in preparing for life extension to regulatory permits.

Long-term fatigue damage due to wave and current conditions (i.e., scatter diagram fatigue) that occurred in the past can be accurately inferred from a combination of metocean data commonly collected through various sources and hindcast databases, and direct measurement of FPS motions. Riser analysis methods are well calibrated for such situations. Thus, the uncertainty around what environmental conditions have actually occurred and what were the associated load cycles is greatly reduced, justifying a lower safety factor than used for future fatigue damage.

Similarly for VIM, the measurement of FPS motions during VIM events can be used as input to a riser analysis to calculate associated fatigue damage.

The assessment of past VIV induced fatigue damage is more challenging due to inherent uncertainties in current data measurements as well as in the VIV prediction tools. Major current events that may cause riser VIV response are limited in occurrences and durations and may be difficult to discern from background or daily currents. Furthermore, VIV motion measurement equipment and tools have very limited life span which makes it difficult to cover the entire riser past life. Thus, it is advisable to continue use of the additional safety factor of 2 on calculated VIV damage.

VIV prediction tools periodically undergo updates and re-calibration, incorporating the latest experimental laboratory and field test data to address uncertainties.

Examples of Fatigue Re-assessment for Life Extension

EXAMPLE 9 – A High safety class riser is installed in 2015. The service life of the riser in the original design basis is 20 years, and this is incorporated into the regulatory permit, which expires in 2035. In the original fatigue analysis, it is projected that the limit of 0.1 damage will be reached at the most critical location in 27 years, or in the year 2042, which corresponds to an annual damage accumulation rate of 0.0037. The limit of 0.1 damage for the rest of the riser will not be reached for well over 100 years. Hence, while the service life expires in 2035, this is an arbitrary date based on permits and not indicative of the actual design life. The riser design life for fatigue goes until 2042 without re-assessment provided the riser and original design conditions have not changed To remain in service after 2042 would require re-assessment of the critical location per API RP 2RIM and API RP 2RD.

EXAMPLE 10 – The same riser is re-assessed in 2042. The riser IM plan has been followed. The operator has condition data reflecting the metocean conditions and FPS motions throughout the life of the riser. Per 9.2.3, the operator demonstrates that the condition of the riser is well documented through regular GVI and corrosion inspections. There has been no damage to the riser or excessive corrosion. The S-N curve from the the original design remains valid. Hence the scatter diagram fatigue damage recorded over the first 27 years can use a reduced safety factor of 3. VIV damage and all future damage remain at a safety factor of 10. The total damage incurred to date is 0.095. Of this, VIV damage accounts for 0.005. Future damage accumulation is expected to continue at 0.0037 per year. The remaining design life, N, can be determined from Equation (40) as follows –

$D_{future} = 0.0037 \times N$	Projected future damage at 0.0037 annual damage rate
$D_{past1} = 0.005$	VIV damage that has already occurred
$D_{past2} = 0.090$	Damage from scatter diagram and VIM that has already occurred

$$(0.0037\ N + 0.005) \times 10 + (0.090 \times 3) \leq 1$$

$$0.037\ N + 0.05 + 0.27 \leq 1$$

N <= (1-0.05-0.27) / 0.32 = 18.4 years

Hence, the service life can be extended to 2042 + 18.4 = 2060.4, provided the operator continues to follow the IM plan including regular GVI and corrosion inspections, and monitoring of metocean conditions and FPS motions, and any other relevant parameters per the IM plan.

EXAMPLE 11 – The same riser is re-assessed in 2042 but in this case, the operator has not had a robust IM plan in place. While a GVI has been performed in preparation for the re-assessment, this has not been routine and the existing IM records do not include much about the history of the riser. Corrosion estimates are by production modelling and occasional coupons from the inlet separator. The riser was designed to have corrosion inhibitor continuously injected, but the pump has had reliability issues and there are windows of months where no corrosion inhibitor is injected, This riser does not meet the criteria for a reduced safety factor, in which case the design life has been reached and the service life can only be extended with additional external and internal inspections to determine the condition of the riser at fatigue critical locations. If these inspections are successful and show the riser to be in good condition and within the parameters of the S-N curve to be used for re-assessment, then the service life may be extended provided an inspection interval is incorporated into the IM plan so that the condition is routinely verified.

A.9.3 Life Extension

General

When discussing life extension of risers, it is important to note that regulatory permits are based on a specific duration that is correlated to operational and reservoir considerations. When initially established, it is somewhat arbitrary because of the broad range of uncertainty in the performance of the hydrocarbon reservoirs, as well as what other discoveries may be made in the area and tied back to the FPS in the future. Hence, the permit life is somewhat arbitrary and is not generally a direct result of available fatigue life, but rather, the target fatigue design life is based on permit life expectations. An operator may choose to design for a longer service life for certain risers depending on the nature of the uncertainties.

For most risers, there are critical locations that incur the most fatigue damage and hence, have the shortest fatigue life. These locations are typically near the top and bottom of the riser where the load transitions to the FPS or seabed. The rest of the riser usually has orders of magnitude more fatigue life and should never experience a fatigue problem unless the condition of the riser changes (e.g., excessive corrosion, mechanical damage).

Fracture Mechanics and ECA

Refer to Sections 5, A.6, 7, and BS 7910 for guidance on crack growth and end-of-life fracture assessments. Refer also to API RP 2RIM on the applicability of fracture mechanics to riser integrity management.

For pipeline risers welded to API 1104, an ECA is required to be performed as a basis to establish UT flaw acceptance criteria. The ECA should take into consideration the anticipated stress histograms (for crack growth) and maximum stress (for end-of-life fracture) of the weld, typically derived from the metocean data such as wave scatter diagrams and current data which are usually used for the S-N fatigue analysis (refer to 5.6).

The ECA is typically used to find the critical initial planar features that are the smallest flaws that can become critical within an inspection interval (and hence fatigue life for an un-inspectable weld) that meets the required design life but may be less than the calculated S-N fatigue life. If the critical initial flaw is left in a fatigue-critical weld, it may result in a reduction in overall fatigue life for the riser compared to the calculated S-N fatigue life, assuming cracks form and propagate on day one of service.

As of the publication date of this Recommended Practice, subsea inspection technology has yet to advance to a point where fatigue cracks can be confidently identified. However, as subsea inspection technologies improve in the future and reach an acceptable level of confidence in characterization of fatigue cracks in critical locations of the riser, the assessment methodology should only be based on a fracture mechanics approach where future damage is assessed based on anticipated fatigue loading. In the instance where a riser has a flaw suspected of being a growing fatigue crack, the future safety factor for fracture mechanics should be half the S-N safety factor. Additionally, alternative methodologies that can be justified can also be used. Selecting the final flaw acceptance criteria takes into account factors besides fatigue life and end-of-life fracture, including workmanship and contractual implications, as well as any adjustment for the sizing tolerance of the UT tools to be used. Note that tighter weld flaw acceptance criteria may lead to more weld rejections, resulting in higher costs and an extended delivery schedule. Varying the criteria depending on the fatigue sensitivity of a particular weld is sometimes considered, although this also comes with complications and productivity constraints.

Typically, the only consideration of ECA around fatigue that enters into the decision process is that for the final flaw-acceptance criteria selected, the ECA maintains a fatigue life within the design life given in the design basis. This is not necessarily the same as the S-N fatigue life and can be shorter than the S-N fatigue life. This does not necessarily imply that therefore the fatigue life of the riser is reduced. The ECA makes a very conservative assumption that the maximum allowable flaw occurs in every weld and at the most critical location within the weld, which is improbable. To make this assumption in determining fitness for service is therefore extremely conservative.

Using the original ECA for life-extension re-assessment should be approached with care. If the records of the original UT inspection of the welds in question (i.e., fatigue sensitive welds near the top and bottom of the riser) are available, and re-examination produces flaw sizing with reasonable confidence, taking into consideration the technology of the original scan, then these flaws can be considered as accurate characteristic data (i.e., as-built data) for the riser, along with any other characteristic data or condition data.

A new ECA can be performed based on updated load histograms and maximum loads using the updated scatter diagram prepared for S-N fatigue re-assessment (refer to 9.2.3) to estimate the remaining fatigue life and accordingly life extension, using a safety factor of half that determined for S-N re-assessment (i.e., half the fatigue design factor, F_{fat}, given in Table 7 for future damage or VIV damage, but not less than 2 for past damage that is well documented per 9.2.3).

If the original UT inspection records cannot be located, or do not exist, ECA can still be used to provide insights into the fitness for service of a riser. Making the very conservative assumption that the critical initial flaw was left in the most fatigue-sensitive weld can be useful for screening purposes but should not be taken as a fatigue life limitation. However, it can be used as a sensitivity giving some insight into what level of risk there may be in not knowing what flaws were accepted for critical welds. Care should be taken not to draw conclusions without a reasonable statistical assessment of the probability of such a flaw existing at the worst location.

In summary, an ECA with existing inspection records or reasonably substantiated assumptions can provide insight into the fatigue robustness of a riser for life extension purposes.

For examples of the application of ECA to life extension assessment of SCRs, refer to Mekha and Gordon (2020) [A26], Mekha (2016) [A27], and Mansour (2023) [A28].

Annex B
(informative)

Riser Analysis

B.1 Riser Analysis

Riser design requires an accurate modelling of the riser and FPS. The loads on the riser come from multiple sources including –

- loads imparted by the motions of the FPS,
- loads associated with the riser hang-off on the FPS (i.e., tensioner system, flexible joint, tapered stress joint, pull tube),
- loads directly bearing on the riser from wave and current,
- loads associated with the motion of the riser itself, and loads associated with the seabed interaction.

The motions of the FPS should be based on a fully coupled model of the FPS and its moorings and risers. Refer to API RP 2T, API RP 2FPS, and API RP 2MET [S10] for appropriate analysis methods and selection of metocean criteria. The selection of metocean criteria and load cases for FPS motions should take into consideration response modes of the risers, and not just the mooring system. The riser designers should work closely with the FPS designers to ensure the load cases adequately consider the response modes of the risers and provide sufficient data to support the riser load cases (Section 4).

FPS motions are dependent on the mass distribution of the FPS itself, particularly the vertical center of gravity (VCG), with the highest allowable VCG usually resulting in the largest pitch and roll motions. Mooring and riser configuration also play a role in determining the FPS motions. If the FPS and/or riser configuration are expected to change during the field life of the FPS, this should be considered in selecting the load cases for riser design. In general, assuming the VCG is at its maximum is a conservative assumption for riser design, but the operator should manage the interface between the riser and global performance analysis to ensure that the appropriate load cases are considered for riser design.

Refer to API RP 2FPS and API RP 2T for guidance on the coupled analysis of different types of FPS. See also DNV-ST-F201 [29] for guidance on riser modeling and statistical analysis. Refer to Ochi [A1] for guidance on estimating extreme values.

The motion of the riser includes a damping component. Because risers are small in diameter compared to typical wave lengths, there is minimal wave diffraction (i.e., inertial loads in Morison's equation terminology), and the wave loading is dominated by viscous effects (I.e., drag). Hence the selection of drag coefficient is critical to riser analysis. The viscous loads essentially represent damping and can be particularly influential in fatigue calculations.

Refer to B.2 for guidance on selecting hydrodynamic coefficients.

Refer to B.3 for guidance on use of allowances for corrosion, wear or erosion in design calculations.

Refer to B.4 for guidance on modelling riser / seabed interaction.

B.2 Selection of Hydrodynamic Coefficients

The selection of hydrodynamic coefficients for added mass and damping is important for an accurate riser analysis. The drag coefficient, C_D, is particularly important because drag is the only appreciable source of damping for both dynamic response in waves and steady forcing in currents.

Deka, *et al* (2022) [B20] provides a thorough survey of empirical studies to support selection of hydrodynamic coefficients for riser design, including guidance on selection.

Drag coefficients vary with flow regime, so the appropriate coefficient for steady current, low-frequency motions, and high-frequency motions may be very different. Using the most conservative coefficient is common practice, but in some circumstances, this can result in very conservative designs, particularly for fatigue.

The primary measures used to characterize the flow regime for riser hydrodynamic coefficients are the Reynolds number (*Re*) and the Keulegan-Carpenter (*Kc*) number.

The Reynolds number relates the riser diameter, fluid velocity, and fluid viscosity. The Keulegan-Carpenter number, *Kc*, relates the riser diameter, fluid velocity, and frequency of oscillation. Note that *Kc* is essentially the inverse of the Strouhal number (*St*) more commonly used in VIV analysis. Drag coefficients are different in steady flow (current dominated) and unsteady flow (wave dominated).

The primary source for drag coefficients is empirical measurement, and most data available was collected to support the design of fixed jackets, made up of tubular members, for extreme loads. Because jacket tubulars do not move, there is minimal interest in low-amplitude fatigue loading. Hence the range of *Re* and *Kc* numbers for most of the data available is focused on extreme design waves (i.e., $H_s > 10\ m$) and for typical jacket tubular sizes (0.3 to 3 meters diameter). In contrast, most risers have hydrodynamic diameters (i.e., including insulation, coatings, marine growth) between 0.25 and 0.6 meters, and the fatigue design can be quite sensitive to the damping in low amplitude sea-states.

There are various industry standards that recommend drag coefficients for different applications. API RP 2A-WSD [08] gives useful guidance for jacket tubulars, but this does not necessarily translate to risers where the dynamics of the riser come into play, particularly around low sea-states.

The presence of marine growth affects drag as well. Projections for marine growth should be included in the design basis and should include thickness and a depth profile, both of which will depend on the local ocean environment. In some tropical areas, marine growth can be quite prolific and extend deep into the water column. There is quite a bit of test data available for “rough” cylinders that covers most types of marine growth.

VIV suppression devices also affect hydrodynamic coefficients. The vendor of the suppression devices should provide test data to confirm the appropriate drag and added mass coefficients in steady and unsteady flow regimes, and the applicable frequency ranges for the latter. Consideration should be given to the impact of marine growth on the drag coefficient for VIV suppression devices, as well as the operators planned cleaning schedule. For example, if the expected marine growth rate is 0.5 inches per year and the operator plans to clean VIV strakes or fairings every two years, then this should be considered in selecting drag coefficients.

Strakes and fairings made with anti-fouling materials or coatings are typically used in the upper section of risers covering the projected marine growth. However, unless data is available verifying the effectiveness throughout the design life, marine growth should be considered to be present.

Once in service, the IM plan should take into consideration marine growth and cleaning cycles, and any reassessment should incorporate the actual marine growth observed. For VIV suppression devices such as fairings that rely on free rotation to align with the flow, marine growth can impede this movement and the IM plan should include ensuring they continue to rotate freely. A fairing may have a very low drag coefficient in line with the flow, but if it is stuck sideways to the flow, the drag coefficient goes up dramatically.

B.3 Allowances for Corrosion, Erosion, or Wear

Corrosion allowance and/or anticipated corrosion rates should be provided by the operator based on reservoir production corrosion modelling. How the corrosion allowance is used in the design varies with the different aspects of design depending on the specifics of the contents of the riser, which may vary with time.

For strength design other than during construction, the corrosion allowance should be removed entirely for the analysis, as the riser is required to meet the design criteria throughout the design life. This applies to the single event fatigue design assessment as well. For construction load cases, including pre-commissioning pressure testing, the full uncorroded thickness may be used so long as it will not be exposed to untreated seawater long enough to initiate corrosion prior to commissioning.

For long-term fatigue assessment, half of the corrosion allowance is typically included, representing an average wall thickness over the service life for a uniform corrosion rate. If corrosion rates are expected to vary over time, it may be necessary to break the life into phases with different corrosion levels considered in each.

> EXAMPLE – A subsea production riser has a design life of 20 years. The reservoir is not sour, but there will be water injection. The water cut is expected to remain relatively low at first, with water breakthrough from the water flood expected between year 7 and 10, after which the corrosion rate is expected to be much greater. In this case, it would be acceptable to use different average wall thicknesses for the first seven years than for the final 13 years. In the IM plan, water cut would be specifically monitored, with reassessment triggers for pre-mature water breakthrough. If the water-cut remains low for longer than 7 years, the ultimate design life could be extended.

While in service, corrosion may be measured through monitoring and in-service inspections, as well as changes in corrosion predictions based on production history. The measured and predicted corrosion rates may be used in riser fatigue re-assessment (e.g., riser life extension).

If excessive wear or erosion are expected during the service life of the riser, allowances should be included in the design basis and incorporated in the design in a manner similar to a corrosion allowance, taking into consideration the time dependence of the wear or erosion predictions.

B.4 Riser / Seabed Interaction

This commentary provides recommendations for the analysis of the interaction between seafloor and SCR/SLWR type risers.

B.4.1 Background

Static Interaction: The first papers to study the static interaction of flexible risers with the seafloor at the touch down point (TDP) were published by Sparks (1984) [B19] and Patel and Seyed (1995) [B18].

Cyclic Interaction: Perhaps the first paper to recognize the importance of correctly modeling the seafloor stiffness at the TDP on the riser's fatigue life under cyclic loading was that published by Audibert et al. (2000) [B10], which adapted an earlier soil-pipe interaction model developed by Audibert et al. (1984) [B9] to model the riser-seafloor interaction.

This topic has been further addressed by a number of researchers, including Bridge et al. (2004) [B11], Clukey et al. (2005) [B14], Bridge and Howells (2007) [B12], Clukey et al. (2007, 2011 and 2017)[B15], [B16], [B17], and most recently by Chen et al. (2019) [B13], who corroborated and confirmed the approach recommended by Clukey et al. (2007, 2011 and 2017) [B15], [B16], [B17] through a series of 1-g and centrifuge model tests.

B.4.2 SCR-Seafloor Interaction Modeling

B.4.2.1 Full Non-Linear Model with Suction

The full non-linear soil response model is based on the soil response curves derived from the CARISIMA and STRIDE JIP experiments, which were published in the public domain.

The curves describing the soil deflection-reaction force relationship shown in Figure 6 combine a Backbone (or undisturbed soil penetration) curve, followed by an Unloading curve, in turn followed by a Suction curve and a Reloading curve before break-out, and finally a Reloading curve after break-out.

Variation of the soil model were based on variation of the following key parameters:

- Undrained shear strength of the soil, or the depth at which the characteristic shear strength is taken from, which controls the shape of the backbone curve.
- Initial embedment of the pipe during its installation, which controls the maximum penetration point and maximum reaction force that is reached by the backbone curve.
- Mobilization distance (MOB), which controls the steepness of the unloading curve and is usually taken as 2.5% of the pipe diameter.
- Maximum suction force (MSF), which controls the maximum negative reaction that can be applied by the soil.
- Break-out displacement (BOD), which controls the displacement range during suction.
- Inflection point position (IP), which controls the reloading curve after break-out and is defined relative to mobilization point in fractions of break-out displacement, viz.

  $$IP = MOB \pm x \cdot BOD$$

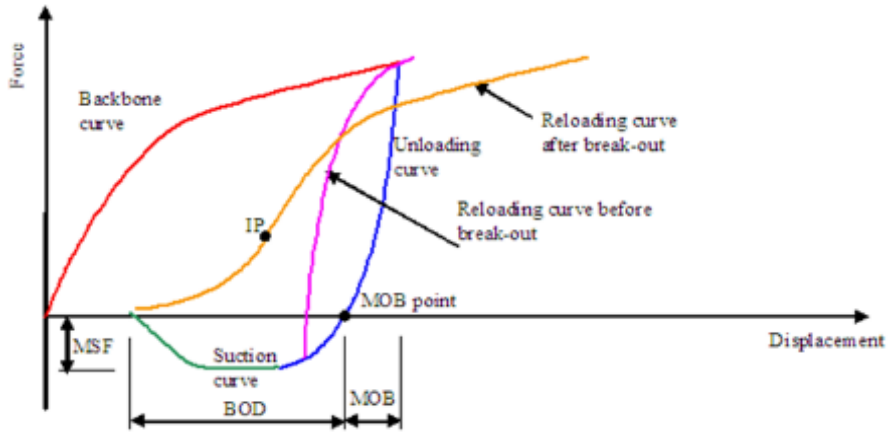


Figure 6 — Full Non-Linear Model with Suction

B.4.2.2 Non-Linear Model without Suction

The non-linear soil response model is a variation of the model described above with no suction, hence has a simplified response schematically depicted in Figure 7.

Figure 7 — Non-Linear Model without Suction

With this simplified model, the only parameters that can be varied are:

- Undrained shear strength of the soil
- Initial embedment, and
- MOB.

B.4.3 Recommendations for Equivalent Linear Stiffness for Design

It is recommended that the designer follow the method presented by Clukey et al. (2011, 2017) [B15], [B16], who reported that a combination of experimental results from GOM clay centrifuge tests and non-

linear numerical modeling can be used to estimate an equivalent linear spring that can be used in riser fatigue design.

As expressed by Audibert et al. (2000) [B10] and Bridge et al. (2004) [B11], the dynamic soil stiffness per unit length of riser along the TDZ can be simply expressed as force (i.e., soil bearing capacity) divided by displacement (i.e., mobilization distance expressed as a fraction of the pipe diameter), viz:

$$K = \frac{Q_U}{z_U} = \frac{Q_U}{\Lambda \mathrm{D}} \tag{45}$$

Where:

Q_U Ultimate soil bearing capacity = $N_c\, s_u$

Where:

N_c soil bearing capacity factor = $5.14\left(1 + 0.23\sqrt{z/B}\right) < 7.5$

z depth of pipe invert (i.e., bottom of pipe)

B bearing width of pipe in contact with the seabed, usually taken as D

s_u undrained shear strength of soil at pipe invert (i.e., bottom of pipe)

z_U mobilization distance normalized to the pipe diameter and expressed as $\Lambda\mathrm{D}$.

Λ a non-dimensional parameter representing the distance, as a function of diameter that the pipe needs to move to mobilize the full soil force.

As recommended by Clukey, et al. (2011) [B15], it is preferable to think in terms of the normalized stiffness or non-dimensional stiffness ratio, k_{stiff}, as this helps get away from particular/site specific values, with k_{stiff} defined as follows:

$$k_{stiff} = K/(N_c S_u) \tag{46}$$

From which it can be seen that k_{stiff} is equal to 1/ Λ. That is, if z_U is equal to 5% to 10% of the pipe diameter (as indicated by Audibert et al. (2000) [B10], k_{stiff} would be 20 to 10, respectively.

Both the centrifuge results and the non-linear numerical simulation suggest an increase of up to 75% in fatigue life when non-linear factors are taken into consideration. To approximate these increased fatigue life predictions, the normalized soil stiffness, K, would be about 4 to 12.5. Also, the non-linear analyses with limited suction suggest normalized stiffness values of 11 to 17. These are significant reductions from values initially reported by others who used normalized stiffness of about 125 for stiffer soil conditions.

Therefore, a preliminary recommendation is to use a normalized soil stiffness ratio of 10 to 20 for GOM soils with a flat seabed. However, other normalized stiffness values could be appropriate for other soil conditions and the designer should be prepared to utilize advanced methods, such as centrifuge testing or analytical codes with non-linear soil capabilities, to justify such values.

B.4.4 Summary and Conclusions for Risers Seafloor Interaction

The following list attempts to summarize the key points in assessing SCR-Seafloor interaction and performing appropriate and robust modeling to calculate fatigue life at the TDP.

1. Recent test programs have demonstrated that suction disappears after only a few (large) cycles.

2. Fatigue design is governed primarily by the 10's of thousands of low amplitude cycles and not by the few (large amplitude) 100's of cycles. Centrifuge tests have helped understanding how the system behaves long-term.

3. Initial normalized stiffness values (i.e., for the static condition) on the order of 100 to 200 are now recognized to be too high. As a riser leaves the seafloor at the TDP, the normalized stiffness decreases substantially.

4. Normalized stiffness values as low as 1 or 2 may exist at the TDP, but the stiffness increases along the TDZ as one moves away from the TDP. Centrifuge testing has been used extensively to define an "average spring", which can be kept constant along the entire TDZ. While it is recognized that this is not a perfect representation of reality, the "average spring" has been calibrated to get a match with the centrifuge results, thus it is felt that this design approach is "fit for purpose" (Clukey, et al, 2011, [B16]).

Annex C
(informative)

Riser Design Examples

C.1 Objective

The design criteria specified in Section 5 allows three different methods to be used for combined stresses, one working stress design (WSD) method (5.4) and two limit state design (LSD) methods (5.5).

The WSD method was originally included in the first edition of API RP 2RD. The WSD method is a sound design methodology, but it is conservative for Survival/ALS load cases in that it does not consider post-yield behavior. The limit state design (LSD) methodology was introduced in the second edition and is further refined in this Recommended Practice. LSD Method 1 is similar to WSD in that both are based on yield as the limiting factor and do not consider post-yield plastic strain. For Extreme/ULS design cases, WSD and LSD Method 1 will lead to similar designs when the internal to external pressure differential is low. For more substantial pressure differentials, WSD will be more conservative.

LSD Method 2, on the other hand, is calibrated to the plastic limit and does allow post-yield strains. This is more useful for Survival/ALS load cases where WSD and LSD Method 1 are conservative because they do not consider any post-yield residual strength.

The underlying intent of the Survival/ALS criteria is that the riser will not fail catastrophically. Using good design practices, the Extreme/ULS should control the design with the Survival/ALS demonstrating that even in a 1,000-year event, it may see some local yielding, but it will not fail catastrophically. However, it is difficult to establish specific criteria that reflects the Survival/ALS intent. Hence the design factors for Survival/ALS are arbitrarily set to 1.0. For WSD and LSD Method 1, this essentially means staying below yield stress, which is conservative for most robust designs. For Method 2, there is some leeway for post-yield behavior.

The test cases presented here are intended to demonstrate that the Survival/ALS design criteria meets the intent for typical, well-designed risers without controlling the design. In other words, it is meant to show that it does not invalidate good sound designs that will not fail catastrophically under ALS conditions. It should, however, single out designs with brittle failure modes when loads move beyond Extreme/ULS levels.

The cases presented here help illustrate the relationship between design methods, load categories and safety class design factors. This is an important check because the first edition did not prescribe the return period for Survival events, only specifying using events that “the designer should evaluate response to survival conditions that exceed the extreme design events”. The second edition was no more prescriptive. A designer could in theory choose a 101-year return period event and meet the ALS criteria.

The present edition requires at least a 1,000-year return period event, so it is useful to verify how existing designs will fare with the new criteria and load categories. The results indicate the design criteria is robust in this respect.

Section 5 gives no specific preference for design methods. However, prudent practice suggests using WSD or LSD Method 1 for the initial design, with Method 2 reserved for resolving local design issues. This ensures a robust design that can absorb some level of design changes in other interfacing systems, such as the FPS mooring system, or the connecting pipeline or wellhead. It also provides some in-service

robustness to damage, changes in service, or life extension. The results presented here follow this approach.

C.2 Test Cases

The riser configurations shown in Table 16 were evaluated using the design criteria defined in Chapter 5 for the Extreme/ULS (100-yr. return period) and Survival/ALS (1,000-yr. return period) environments. All three example risers are in the Gulf of Mexico and the environments are hurricanes, designated H100 and H1000 respectively.

The risers were selected to cover a range of typical configurations, including a subsea flowline SCR from a TLP, a TTR from a Spar, and a gas export SCR from a Semi-submersible. During the design process, several different locations on the riser were evaluated. The results reported here are only for the critical locations that control that particular riser design.

Table 16 – Riser Configurations of Test Cases

	CASE 1	CASE 2	CASE 3
Riser Type	Flowline SCR	TTR	Export SCR
Host Type	TLP	Spar	Semi
Water Depth	2900 ft	7800 ft	8500 ft
Hang-off Angle	8 deg	N/A	7 deg
Pipe	API 5L, seamless	API 5L, seamless	API 5L, seamless
Nominal Pipe Size	6.625” OD x 0.844” wall	14.126” OD x 0.85” wall	16” OD x 1” wall
Critical location	Stress joint at the hang-off point	Stress joint at the Spar keel	Near the touch-down point

The following assumptions apply to the results presented here unless specifically noted otherwise –

- Tensions and moments are the maximum for each, independent of time, and may or may not occur simultaneously;
- Linear elastic material models are used.

C.3 Case 1 – Flowline SCR from a TLP

Case 1 is a low D/t SCR typical of a subsea flowline. The critical location is at top of the riser, including the tapered stress joint, which is a machined forging, and the first joint of welded pipe. The touch-down point was also checked and was found not to control the design and is not included here. Table 17 gives the section and material properties at the locations considered.

The hang-off point for this SCR is at the topsides elevation, above MSL, so the external pressure, p_e, is atmospheric. This riser is in the Gulf of Mexico where all personnel are evacuated for hurricanes and this riser is blown down prior to evacuation, so for the Extreme/ULS and Survival/ALS cases, the internal pressure is also atmospheric. Hence there is no risk to personnel at the critical locations and the safety class is Low.

The resulting utilizations for both H100 and H1000 cases are summarized in Table 18, where utilization is defined as the actual quantity from the riser analysis over the allowable quantity, so utilization less than or equal to one passes the criteria. Green and red text are used to more clearly illustrate pass (green) vs fail (red). The details behind these utilizations are given in Tables 19 and 20.

For the H100 environment, the utilization factors for all three methods are adequate. For the H1000 environment, yielding occurs and the LSD methods are applied. Using a linear material model, the first location has a utilization of 1.08, which does not pass any of the methods. However, applying a nonlinear material model results in an acceptable utilization. The details of the nonlinear model are not presented here.

Note that in both environments, WSD and LSD Method 1 are virtually identical for these locations because the internal and external pressures above the water line (at the critical locations) are equal during hurricane abandonment. Without pressure differential across the pipe wall to cause hoop and radial stresses, WSD and LSD Method 1 formulas reduce to be the same.

Figure 8 shows the moment vs tension limits for the first location (stress joint base of taper 1) for LSD Methods 1 and Method 2. It also shows the analytical results for ULS and ALS cases, illustrating the significant improvement when using nonlinear material properties for the ALS case.

As a side note, the results in Tables 19 and 20 of the locations within the stress joint forging above it. This seems counter-intuitive, but these tables represent the maximum loads for any environmental heading, so the results for each location may correspond to different headings and correspond to the maximum combined stress. In this case, the highest stresses in the stress joint occur in an out-of-plane load case (i.e., where the environment is perpendicular to the plane of the riser) with higher bending moments. The maximum stress in the upper pipe occurs in an in-plane taut load case (i.e., where the environment is aligned with the plane of the riser and pushing the FPS away from the touch-down point, with higher tension).

Table 17: Case 1 – Riser Properties

Location	OD	Wall Thickness	Buckling Strain	Yield Strength	Section Area	Section Moment of Inertia	Internal Pressure p_i	External Pressure p_e	Ovality δ_0	Safety Class
	(in)	(in)	(%)	(psi)	(in^2)	(in^4)	(psi)	(psi)	(-)	(-)
			Eq. (5)						Eq. (15)	Table 4
Stress Joint base of Taper1	11.000	3.146	14.3	85,000	77.62	694.57	0.00	0.00	0.000	Low
Stress Joint tip of Taper1	7.000	1.146	8.2	85,000	21.08	93.74	0.00	0.00	0.000	Low
Stress Joint tip of Taper2	6.705	0.9985	7.4	85,000	17.90	75.10	0.00	0.00	0.000	Low
Upper Riser Pipe (~at MSL)	6.625	0.844	6.4	70,000	15.33	65.40	0.00	0.00	0.005	Low

Table 18: Case 1 – Utilization Summary

	Extreme / ULS (H100)			Survival / ALS (H1000)		
Location	WSD	Method 1	Method 2	WSD	Method 1	Method 2
Stress joint base of Taper1	0.87	0.87	0.76	1.22	1.22	0.97
Stress joint tip of Taper1	0.92	0.92	0.71	1.25	1.25	1.00
Stress joint tip of Taper2	0.77	0.77	0.58	1.04	1.04	0.81
Upper riser pipe	0.89	0.89	0.64	1.17	1.17	0.87

Table 19: Case 1 – H100 Results

Location	F_D (-)	P_b (psi) Eq. (1)	P_c (psi) Eq. (2)	T_y (lb) Eq. (6)	M_y (in-lb) Eq. (7)	M_p (in-lb) Eq. (8)	F_{sc} (-) Table 6	M (in-lb)	T (lb)
Stress Joint base of Taper1	0.8	68,739		6,598,093	15,034,022	17,377,484	1.04	10,210,404	116,100
Stress Joint tip of Taper1	0.8	32,128		1,791,456	2,722,272	3,380,817	1.04	1,834,692	111,300
Stress Joint tip of Taper2	0.8	28,641		1,521,552	2,237,142	2,792,006	1.04	1,221,660	111,000
Upper Riser Pipe (~at MSL)	0.8	20,116		1,072,984	1,583,784	1,988,480	1.04	957,444	116,600

Location	WSD			LSD - Method 1			LSD - Method 2		
	Eq. (26)			Eq. (27), (28)			Eq. (30), (31)		
	LHS(1)	RHS(2)	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)
Stress Joint base of Taper1	59,224	68,000	0.871	0.697	0.800	0.871	0.588	0.769	0.764
Stress Joint tip of Taper1	62,567	68,000	0.920	0.736	0.800	0.920	0.543	0.764	0.711
Stress Joint tip of Taper2	52,618	68,000	0.774	0.619	0.800	0.774	0.438	0.761	0.575
Upper Riser Pipe (~at MSL)	49,924	56,000	0.891	0.713	0.800	0.891	0.481	0.752	0.640

Location	Safety Class Factor	Strain Check Eq. (13), (14)			
	$f_{sc,B}$ Table 5	Bending Strain (LHS)	Strain Limit (RHS)	Utilization (LHS/RHS)	Total Strain
	(-)	(%)	(%)	(-)	(%)
Stress Joint base of Taper1	2.00	0.27	7.15	0.038	0.28
Stress Joint tip of Taper1	2.00	0.23	4.09	0.056	0.25
Stress Joint tip of Taper2	2.00	0.18	3.72	0.049	0.20
Upper Riser Pipe (~at MSL)	2.00	0.16	3.18	0.051	0.19

NOTES: (1) LHS denotes the left-hand side of the referenced equation.
(2) RHS denotes the right-hand side of the referenced equation.

Table 20: Case 1 – H1000 Results

Location	F_D (-)	P_b (psi) Eq. (1)	P_c (psi) Eq. (2)	T_y (lb) Eq. (6)	M_y (in-lb) Eq. (7)	M_p (in-lb) Eq. (8)	F_{sc} (-) Table 6	M (in-lb)	T (lb)
Stress Joint base of Taper1	1.0	68,739	-	6,598,093	15,034,022	17,377,484	1.04	18,019,584 (16,219,700) (4)	119,900
Stress Joint tip of Taper1	1.0	32,128	-	1,791,456	2,722,272	3,380,817	1.04	3,234,036	115,200
Stress Joint tip of Taper2	1.0	28,641	-	1,521,552	2,237,142	2,792,006	1.04	2,150,064	114,800
Upper Riser Pipe (~at MSL)	1.0	20,116	-	1,072,984	1,583,784	1,988,480	1.04	1,674,132	122,400

Location	WSD			LSD - Method 1			LSD - Method 2		
	Eq. (26)			Eq. (27), (28)			Eq. (30), (31)		
	LHS(1)	RHS(2)	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)
Stress Joint base of Taper1	103,425	85,000	1.217	1.217	1.000	1.217	1.037	0.961	1.079 (0.97) (4)
Stress Joint tip of Taper1	106,445	85,000	1.252	1.252	1.000	1.252	0.957	0.957	1.000
Stress Joint tip of Taper2	88,105	85,000	1.037	1.037	1.000	1.037	0.770	0.955	0.807
Upper Riser Pipe (~at MSL)	81,978	70,000	1.171	1.171	1.000	1.171	0.842	0.946	0.890

Location	Safety Class Factor	Strain Check Eq. (13), (14)			
	$f_{sc,\varepsilon}$ Table 5	Bending Strain (3) (LHS)	Strain Limit (RHS)	Utilization (LHS/RHS)	Total Strain
	(-)	(%)	(%)	(-)	(%)
Stress Joint base of Taper1	2.0	0.64	7.15	0.090	0.65
Stress Joint tip of Taper1	2.0	0.35	4.09	0.085	0.37
Stress Joint tip of Taper2	2.0	0.27	3.72	0.072	0.29
Upper Riser Pipe (~at MSL)	2.0	0.30	3.18	0.102	0.32

NOTES:
(1) LHS denotes the left-hand side of the referenced equation.
(2) RHS denotes the right-hand side of the referenced equation.
(3) Elastic perfectly-plastic material model
(4) The results in this table for Method 2 use linear material properties. However, in this instance, the utilization is greater than 1.0. Applying elastic perfectly-plastic material properties reduces the bending moment and the resulting utilization is 0.97 (numbers shown in parentheses).

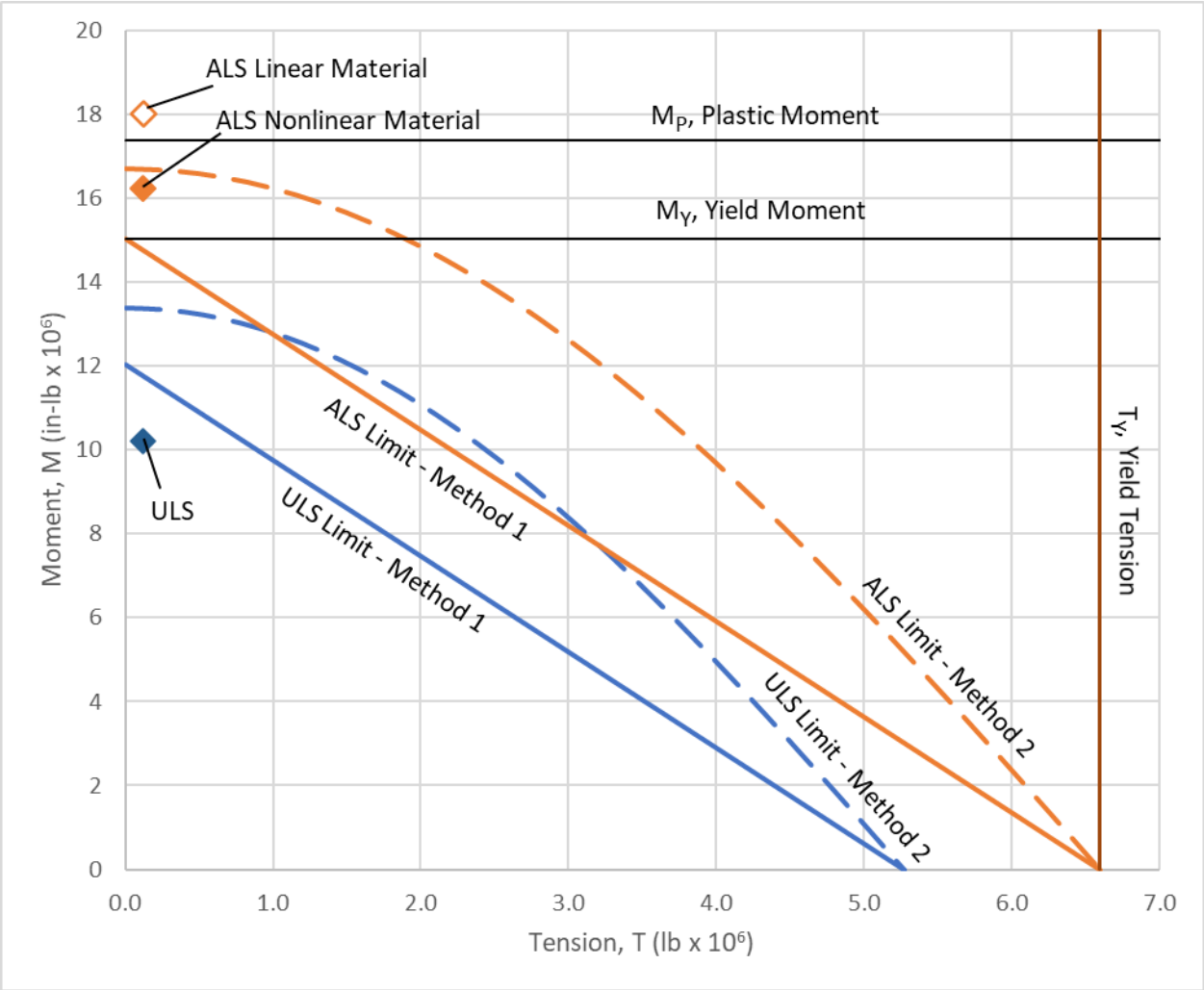


Figure 8: Case 1 – Moment vs Tension at Stress Joint, Base of Taper 1

C.4 Case 2 – TTR from a Spar

Case 2 is a TTR from a Spar. The results shown are for several locations near the keel joint, which is a machined forging. Table 21 gives the section and material properties at the locations considered.

The critical locations near the keel of the Spar, so there is positive external pressure, p_e. This riser is in the Gulf of Mexico where all personnel are evacuated for hurricanes. However, this riser is not blown down prior to evacuation and contains hydrocarbons under pressure. Hence, per (5.1.3) the safety class is Normal.

The resulting utilizations for both H100 and H1000 cases are summarized in Table 22. The details are given in Tables 23 and 24.

For both the Extreme/ULS (H100) environment, and the Survival/ALS (H1000) environment, some section yielding is expected at this location. LSD Method 2, which considers post-yield behavior, is needed for these load cases to pass. To demonstrate that strains remained small at the lower keel joint/connector weld, strain was estimated assuming elastic perfectly-plastic material but are not recorded here. The moment-curvature relationship for this specific location with true wall tension of 1,240 kips is shown in Figure 9. The plot shows that the curvature, which is 0.00023 in^{-1}, at the maximum bending moment is just beyond the linear range. The bending strain on the outside diameter is then 0.198%. After adding in the strain due to true wall tension, the total strain is 0.29%, which is considered small.

Note that, like Case 1, there is close correlation between WSD and LSD Method 1 results because the pressure differential is quite small.

Figure 10 shows the moment vs tension limits for the first location (tip of lower keel-joint taper) for LSD Methods 1 and Method 2, along with the analytical results for ULS and ALS cases.

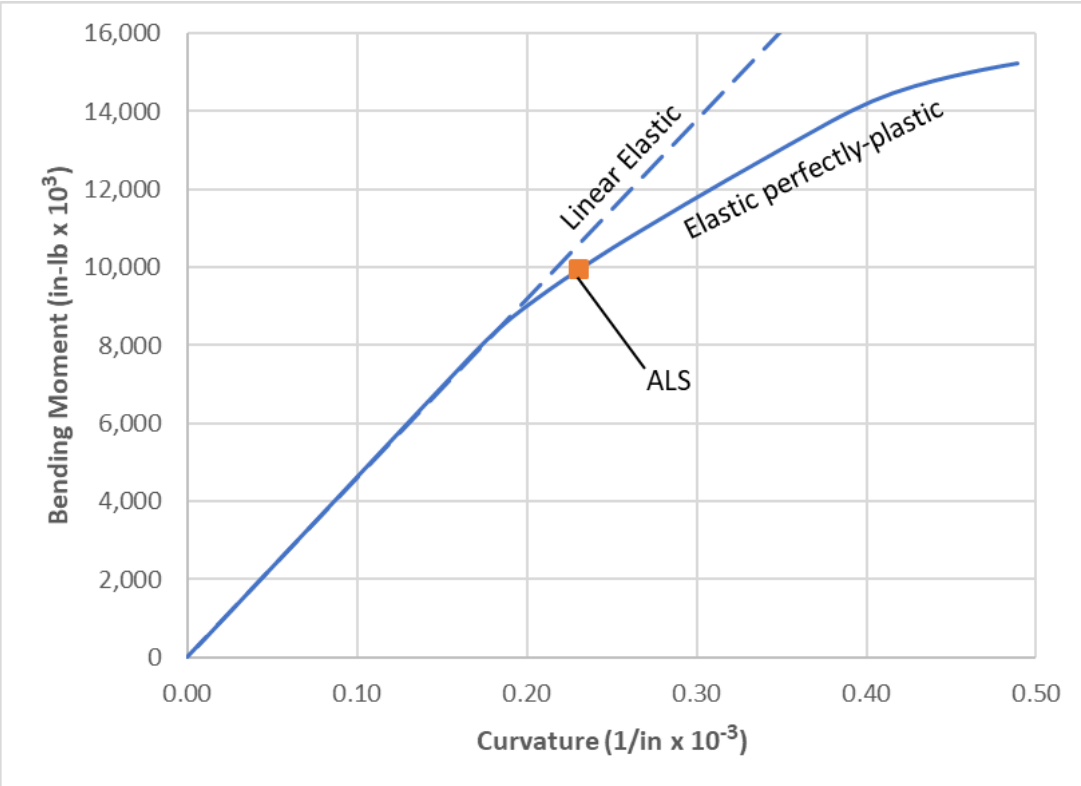


Figure 9: Case 2 – H1000 Moment-Curvature Relationship at Lower Keel Joint/Connector Weld for Elastic Perfectly-Plastic Material Assumption at True Wall Tension of 1240 kips

Table 21: Case 2 – Riser Properties

Location	OD	Wall Thickness	Buckling Strain	Yield Strength	Section Area	Section Moment of Inertia	Internal Pressure p_i	External Pressure p_e	Ovality δ_0	Safety Class
	(in)	(in)	(%)	(psi)	(in^2)	(in^4)	(psi)	(psi)	(-)	(-)
			Eq. (5)						Eq. (15)	Table 4
Tip of Lower Keel Joint Taper	17.250	0.935	2.71	80,000	47.92	1,599.77	367.50	230.30	0.00	17.250
Lower Keel Joint/Connector Weld	17.250	0.895	2.59	73,000	45.99	1,542.17	368.20	230.80	0.00	17.250

Table 22: Case 2 – Utilization Summary

	Extreme / ULS (H100)			Survival / ALS (H1000)		
Location	WSD	Method 1	Method 2	WSD	Method 1	Method 2
Tip of Lower Keel Joint Taper	1.02	1.02	0.71	0.99	0.99	0.69
Lower Keel Joint/Connector Weld	1.12	1.12	0.80	1.08	1.08	0.77

Table 23: Case 2 – H100 Results

Location	F_D (-)	P_b (psi) Eq. (1)	P_c (psi) Eq. (2)	T_y (lb) Eq. (6)	M_y (in-lb) Eq. (7)	M_p (in-lb) Eq. (8)	F_{sc} (-) Table 6	M (in-lb)	T (lb)
Tip of Lower Keel Joint Taper	0.8	8,881	6,593	3,833,880	15,688,798	19,932,003	1.14	8,396,520	1,076,900
Lower Keel Joint/ Connector Weld	0.8	7,642	5,769	3,356,961	13,766,879	17,493,644	1.14	7,884,000	1,076,600

Location	WSD			LSD - Method 1			LSD - Method 2		
	Eq. (26)			Eq. (27), (28)			Eq. (30), (31)		
	LHS(1)	RHS(2)	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)
Tip of Lower Keel Joint Taper	65,295	64,000	1.020	0.816	0.800	1.020	0.421	0.598	0.705
Lower Keel Joint/ Connector Weld	65,226	58,400	1.117	0.893	0.800	1.117	0.451	0.567	0.795

Location	Safety Class Factor	Strain Check Eq. (13), (14)			
	$f_{sc,B}$ Table 5	Bending Strain (LHS)	Strain Limit (RHS)	Utilization (LHS/RHS)	Total Strain
	(-)	(%)	(%)	(-)	(%)
Tip of Lower Keel Joint Taper	2.50	0.151	1.08	0.139	0.229
Lower Keel Joint/ Connector Weld	2.50	0.147	1.04	0.142	0.228

NOTES: (1) LHS denotes the left-hand side of the referenced equation.
(2) RHS denotes the right-hand side of the referenced equation.

Table 24: Case 2 – H1000 Results

Location	F_D (-)	P_b (psi) Eq. (1)	P_c (psi) Eq. (2)	T_y (lb) Eq. (6)	M_y (in-lb) Eq. (7)	M_p (in-lb) Eq. (8)	F_{sc} (-) Table 6	M (in-lb)	T (lb)
Tip of Lower Keel Joint Taper	1.0	8,881	6,593	3,833,880	15,688,798	19,932,003	1.14	10,605,840	1,195,400
Lower Keel Joint/ Connector Weld	1.0	7,642	5,769	3,356,961	13,766,879	17,493,644	1.14	9,947,400	1,195,200

Location	WSD			LSD - Method 1			LSD - Method 2		
	Eq. (26)			Eq. (27), (28)			Eq. (30), (31)		
	LHS(1)	RHS(2)	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)
Tip of Lower Keel Joint Taper	79,032	80,000	0.988	0.988	1.000	0.988	0.532	0.774	0.688
Lower Keel Joint/ Connector Weld	78,745	73,000	1.079	1.079	1.000	1.079	0.569	0.743	0.765

Location	Safety Class Factor	Strain Check Eq. (13), (14)			
	$f_{sc,B}$ Table 5	Bending Strain (3) (LHS)	Strain Limit (RHS)	Utilization (LHS/RHS)	Total Strain
	(-)	(%)	(%)	(-)	(%)
Tip of Lower Keel Joint Taper	2.50	0.191	1.08	0.176	0.277
Lower Keel Joint/ Connector Weld	2.50	0.195	1.04	0.188	0.285

NOTES:
(1) LHS denotes the left-hand side of the referenced equation.
(2) RHS denotes the right-hand side of the referenced equation.
(3) Elastic perfectly-plastic material model

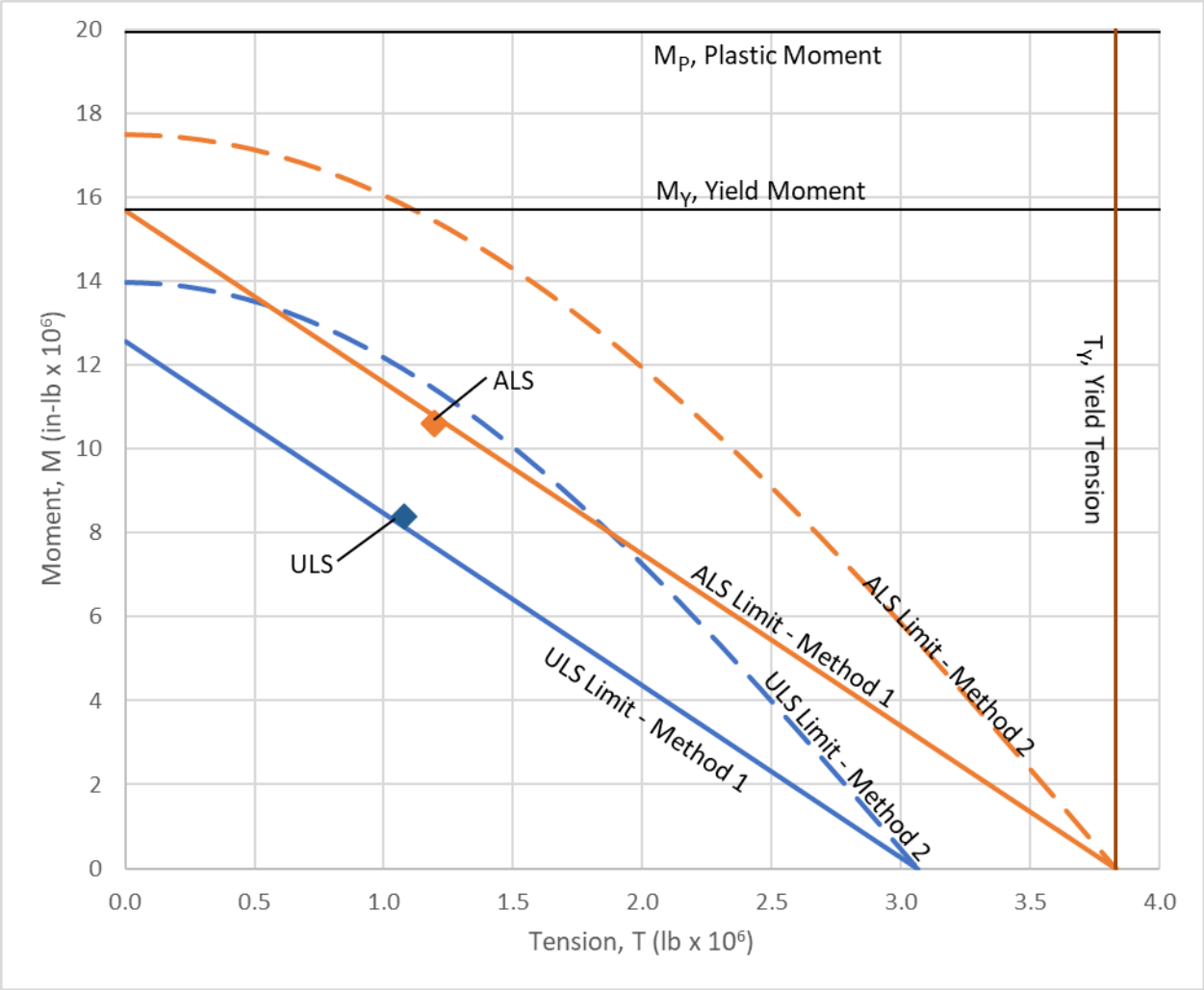


Figure 10: Case 2 – Moment vs Tension at Tip of the Lower Keel Joint Taper

C.5 Case 3 – Gas Export SCR from a Semi-submersible

Case 3 is a gas export SCR from a semisubmersible. Table 25 gives the section and material properties at the locations considered.

The resulting utilizations for both H100 and H1000 cases are summarized in Table 26. The details are given in Tables 27 and 28.

This SCR has a relatively high D/t and light unit weight, compared to the SCR in Case 1. Such configurations could result in yielding near the touch-down point for the Survival/ALS (H1000) environment. This is aggravated by the vertical motions of a semi-submersible compared to a TLP in Case 1. Hence, the critical location for this riser is at the touch-down point, rather than at the stress joint in Case 1. This is addressed successfully using LSD Method 2. Although not included here, the results for the stress joint location passed WSD criteria for both the Extreme/ULS and Survival/ALS environments.

Note that in this case, there is significant improvement moving from WSD to LSD Method 1 for the Survival/ALS (H1000) case. This is because the strains are significantly higher than in Case 1 or Case 2, and the limit state design takes this into account.

Figure 11 shows the moment vs tension limits at the touch-down point location for LSD Methods 1 and Method 2. It also shows the analytical results for ULS and ALS cases, illustrating the significant improvement when using the correlated tension and moment, rather than the independent maxima for each.

Unlike Case 1 and Case 2, this case has a pressure differential ($p_e - p_i$), so it is useful to see the relationship between pressure differential and allowable bending strain. This is illustrated in Figure 12. While this case has a relatively low pressure differential (478 psi, as indicated in the figure), a more substantial differential would result in a significantly lower allowable strain, illustrating the "guard-rail" function of this limit. This case is Normal safety class. For a High safety class, the limit would be further reduced.

Note that the H1000 ALS case currently shows a utilization of 1.007 using Method 2 with linear material properties. It will drop below 1.0 using nonlinear material properties, but the work has not been done. This is a good illustration of how ev,en for a lightweight, high *D/t* SCR in very deep water with compression near the touch-down point, it will still safely pass Method 2 ALS for the H1000 storm, confirming that the Survival/ALS criteria of a 1000 year return period still passes for well-designed risers without unusual nonlinear failure mechanisms.

Table 25: Case 3 – Riser Properties

Location	OD (in)	Wall Thickness (in)	Buckling Strain (%) Eq (5)	Yield Strength (psi)	Section Area (in^2)	Section Moment of Inertia (in^4)	Internal Pressure p_i (psi)	External Pressure p_e (psi)	Ovality δ_0 (-) Eq. (15)	Safety Class (-) Table 4
Touch-down point	16.000	1	3.13	65,000	47.12	1,331.25	3,300.00	3,777.78	0.0025	Normal

Table 26: Case 3 – Utilization Summary

	Extreme / ULS (H100)			Survival / ALS (H1000)			
Location	WSD	Method 1	Method 2	WSD	Method 1	Method 2	Strain

							Check
Touch-down point	1.062	1.063	0.875	1.21	1.21	1.007	0.332

Table 27: Case 3 – H100 Results

Location	F_D (-)	P_b (psi) Eq. (1)	P_c (psi) Eq. (2)	T_y (lb) Eq. (6)	M_y (in-lb) Eq. (7)	M_p (in-lb) Eq. (8)	F_{sc} (-) Table 6	M (in-lb)	T (lb)
Touch-down point	0.8	8,533	7,202	3,063,053	11,537,499	14,646,667	1.14	8,862,141	246,408

Location	WSD			LSD - Method 1			LSD - Method 2		
	Eq. (26)			Eq. (27), (28)			Eq. (30), (31)		
	LHS(1)	RHS(2)	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)
Touch-down point	55,243	52,000	1.062	0.849	0.798	1.063	0.605	0.691	0.875

Location	Safety Class Factor	Strain Check Eq. (13), (14)			
	$f_{sc,s}$ Table 5	Bending Strain (RHS)	Strain Limit (LHS)	Utilization (LHS/RHS)	Total Strain
	(-)	(%)	(%)	(-)	(%)
Touch-down point	2.50				

NOTES: (1) LHS denotes the left-hand side of the referenced equation.
(2) RHS denotes the right-hand side of the referenced equation.

Table 28: Case 3 – H1000 Results

Location	F_D (-)	P_b (psi) Eq. (1)	P_c (psi) Eq. (2)	T_y (lb) Eq. (6)	M_y (in-lb) Eq. (7)	M_p (in-lb) Eq. (8)	F_{sc} (-) Table 6	M (in-lb)	T (lb)
Touch-down point	1.0	8,533	7,202	3,063,053	11,537,499	14,646,667	1.14	12,881,589	273,516
Correlated T, M (4)									*143,289*

Location	WSD			LSD - Method 1			LSD - Method 2		
	Eq. (26)			Eq. (27), (28)			Eq. (30), (31)		
	LHS(1)	RHS(2)	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)	LHS	RHS	Utilization (LHS/RHS)
Touch-down point	78,437	65,000	1.207	1.206	0.998	1.208	0.879	0.867	1.014
Correlated T, M (4)	*75,676*		*1.164*	*1.163*		*1.165*		*0.873*	*1.007* (5)

Location	Safety Class Factor	Strain Check Eq. (13), (14)			
	$f_{sc,B}$ Table 5	Bending Strain (3)	Strain Limit	Utilization (LHS/RHS)	Total Strain
	(-)	(%)	(%)	(-)	(%)
Touch-down point	2.50	0.64	1.077	0.603	0.65
Correlated T, M (4)	*2.50*	*0.40*	*1.077*	*0.367*	

NOTES:
(1) LHS denotes the left-hand side of the referenced equation.
(2) RHS denotes the right-hand side of the referenced equation.
(3) Elastic perfectly-plastic material model
(4) Time-correlated moment and tension producing the highest utilization, rather than the independent maximums used in the base results. Only values that change are shown.
(5) A nonlinear material model reduces the moment sufficiently to bring this below 1.0, although the result is not shown here.

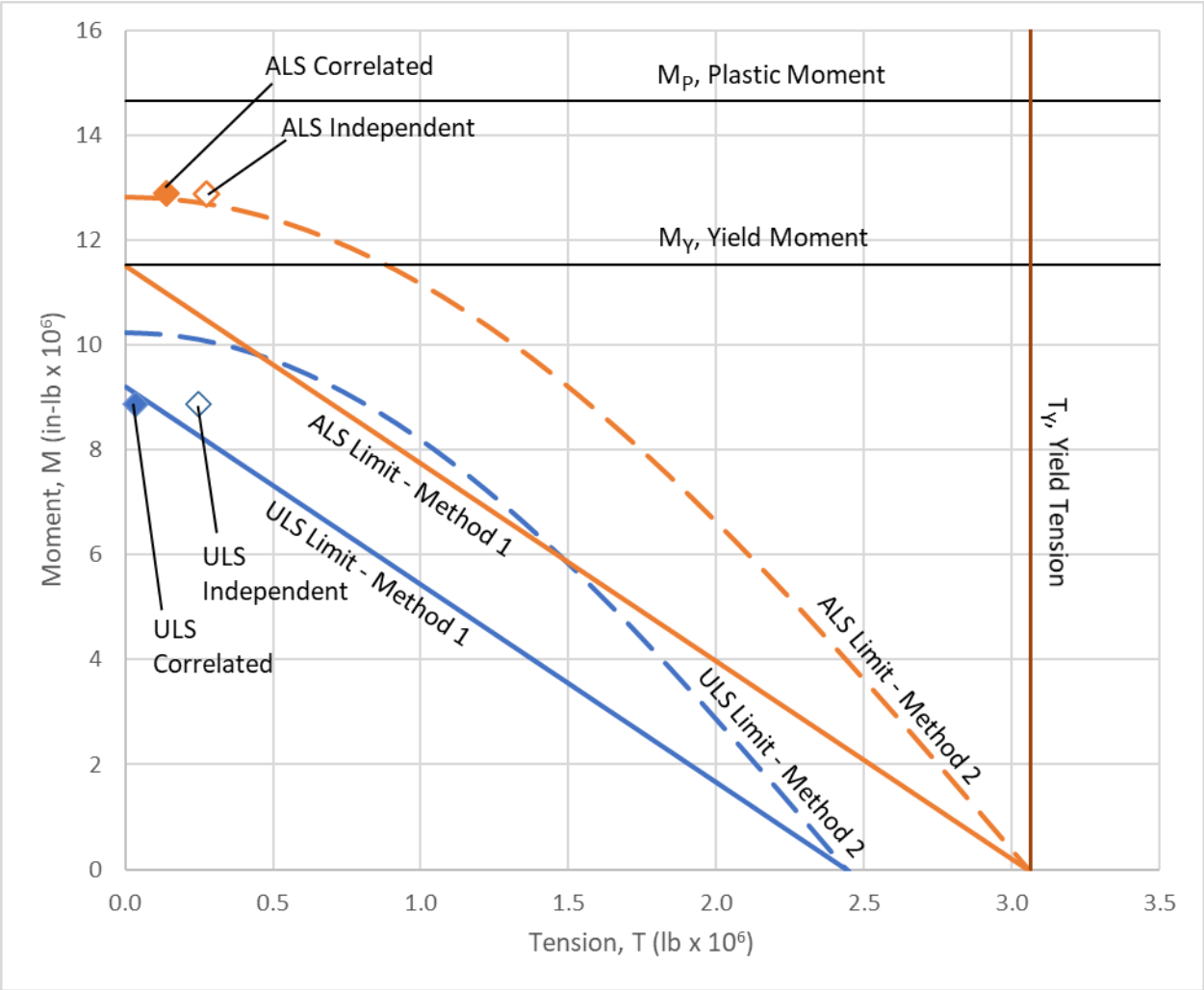


Figure 11: Case 3 – Moment vs Tension near the Touch-down point

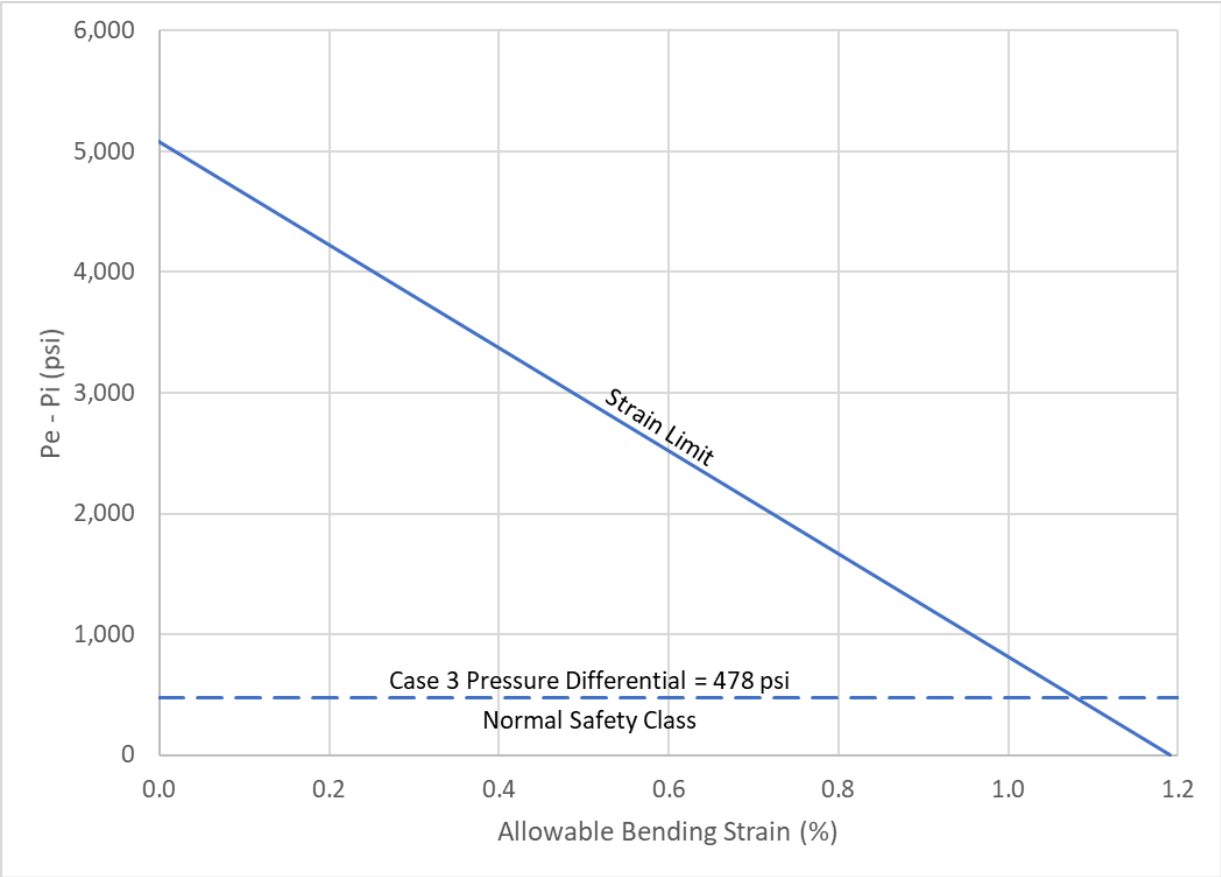


Figure 12: Case 3 – Pressure Differential vs Allowable Bending Strain (%) per Equation 14

Annex D
(informative)

Low-Cycle Fatigue Examples

D.1 Example – Reeling

In this example, taken from Mansour (2022) [D1], X65 seamless pipe joints of 219.1mm (8.625in) outer diameter are used for an SCR. The SCR is installed by reel-lay. Details of the pipe, reel, and calculations are given in Table 29. The fatigue ductility coefficients "a" and "b" should be obtained from the design ε-2N curve (mean curve minus two standard deviations of log 2N at a minimum) of the weld (or pipe) material under consideration, either from the literature if available or as established by testing. Using the example ε-2N curve given in Mansour (2022) [D1], the fatigue ductility coefficients corresponding to the mean minus two standard deviations curve are: a ≈ 0.45 and b ≈ -0.656.

Table 29: Example - Reeling

Parameter	Value
D_{Pipe} (mm)	219.1
D_{Reel} (m)	19.5
Total Strain, $\varepsilon_{ti} = D_{Pipe} / (D_{Pipe} + D_{Reel})$ (1) (-)	0.0111
Elastic Strain ε_{ei} (2) (-)	0.0025
Plastic Strain, $\varepsilon_i = \varepsilon_{ti} - \varepsilon_{ei}$ (-)	0.0086
No. of Reeling Cycles, n_i (3)	4
No. of Cycles to Failure N_i, $\varepsilon_i = a\ (2\ N_i)^b$	210
LCF Damage, $D = n_i / N_i$ (-)	0.019

Notes
1. No strain amplification factor is applied.
2. Guesstimated value -- should be obtained from the stabilized cyclic stress-strain curve.
3. Assumed value.

Four cycles of reeling produce 1.9% damage excluding any safety factors. While this is relatively small, it can become significant as the pipe diameter increases or reel diameter decreases.

It should be noted that ignoring the elastic strain component and assuming that the plastic strain equals the total strain can be unnecessarily conservative. For instance, assuming the plastic strain in the example given is equal to 0.0111 results in fatigue damage of 0.028 or approximately 50% higher fatigue damage.

Another issue to be noted is that S-N fatigue testing of welds of risers (and pipeline sections subjected to fatigue) installed by reel-lay is typically performed after the fatigue test samples have been subjected to bending cycles simulating reel-lay. As such, the impact of reeling cycles is captured in validating the welds.

The fatigue analysis requires calculating the fatigue damage from all sources, including installation, in order to assess the fatigue life and verify it meets or exceeds the design life. Installation fatigue analysis is typically performed at late stages of the design or after the design has been completed; therefore, installation damage is typically assigned a percentage allowance in the fatigue analysis (typically 5%-10%). Consequently, calculating the reeling LCF damage is beneficial to assess what allowance to assign to reel-lay installation damage and avoid assigning too low or too high a value.

D.2 Example – Fatigue Analysis

Fatigue analysis of the same SCR considered in the reeling example showed that the SCR's response in the touchdown region includes multiple inelastic cycles. Details of the cycles and calculations are given in Table 30. The LCF produces 9.7% damage excluding any safety factors.

Table 30: Example – Fatigue Analysis

Parameter	Block 1	Block 2	Block 3	Block 4
Total Strain (1) (-)	0.004	0.006	0.007	0.008
Elastic Strain ε_{ei} (2) (-)	0.0022	0.0023	0.0024	0.0025
Plastic Strain, $\varepsilon_i = \varepsilon_{ti} - \varepsilon_{ei}$ (-)	0.0018	0.0037	0.0046	0.0055
No. of Cycles, n_i (1)	38	23	15	9
No. of Cycles to Failure N_i, $\varepsilon_i = a\,(2\,N_i)^b$	2173	761	536	408
LCF Damage (Eqn. 1)	0.017	0.030	0.028	0.022
Total LCF Damage, $D = n_i / N_i$ (-)	0.097			

Notes
1. From the analysis.
2. Guesstimated values -- should be obtained from the stabilized cyclic stress-strain curve.

The LCF damage should be added to the HCF damage (S-N damage) to obtain the total damage and appropriate safety factors consistent with S-N damage should be used, whether long-term or single-event.

It should be noted that the environmental loads have been exaggerated significantly to ensure obtaining inelastic cycles. It should also be noted that the impact of ratcheting on LCF has not been included in these examples for simplicity. The impact of LCF on fracture toughness and weld flaw acceptance criteria has also not been included either and can be found elsewhere, e.g., [S34].

Annex E
(informative)

Bibliography

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[S02]	API RP 16Q	*Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*
[S03]	API Spec 17E	*Specification for Subsea Umbilicals 5th 2017*
[S04]	API Standard 17G	*Design and Manufacture of Subsea Well Intervention Equipment*
[S07]	API TR 17TR7	*Verification and Validation of Subsea Connectors*
[S08]	API RP 2A-WSD	*Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design 22nd 2014*
[S09]	API Spec 2H	*Specification for Carbon Manganese Steel Plate for Offshore Structures*
[S10]	API RP 2MET	*Derivation of Metocean Design and Operating Considerations*
[S11]	API RP 2RD (First Edition)	*Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs)*
[S12]	API STD 2RD (Second Edition)	*Dynamic Risers for Floating Production Systems*
[S13]	API Spec 2W	*Steel Plates Produced by Thermo-Mechanically Controlled Processing for Offshore Structures*
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[S15]	ASME B31.8	*Gas Transmission and Distribution Piping Systems*
[S16]	ASME BPVC, Section VIII, Div 2	*Rules for Construction of Pressure Vessels - Division 2 - Alternative Rules*
[S17]	ASTM A36/A36M	*Standard Specification for Structural Steel*
[S18]	ASTM A516/A516M	*Standard Specification for Pressure Vessel Plates, Carbon Steel, for Moderate- and Lower-Temperature Service*
[S19]	ASTM A537/A537M	*Standard Specification for Pressure Vessel Plates, Heat-Treated, Carbon-Manganese- Silicon Steel*
[S20]	ASTM E2375	*Standard Practice for Ultrasonic Testing of Wrought Products*
[S21]	AWS D1.1/D1.1M	*Structural Welding Code - Steel*
[S23]	DNV-RP-C204	*Structural design against accidental loads*
[S28]	DNV-ST-C501	*Composite components*

Ref No.	Shortcut for Text	Citation
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[S29]	DNV-ST-F201	*Riser Systems*
[S25]	DNV-RP-F203	*Riser Interference*
[S26]	DNV-RP-F204	*Riser fatigue*
[S27]	DNV-RP-N101	*Risk management in marine and subsea operations*
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[S38]	ISO 18797-1	*Petroleum, petrochemical and natural gas industries, External corrosion protection of risers by coatings and linings, Part 1: Elastomeric coating systems-polychloroprene or EPDM*
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[S32]	API BULLETIN 2INT-DG	*Interim Guidance for Design of Offshore Structures for Hurricane Conditions*
[S33]	API BULLETIN 2INT-EX	*Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions*
[S35]	DNV-RP-0034	*Steel forgings for subsea applications – Technical requirements*
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