

Design and Analysis of Stationkeeping Systems for Floating Offshore Structures

API RECOMMENDED PRACTICE 2SK
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Introduction

API standards for the analysis and design of moored vessels have evolved since the first editions of API 2P, API 2FP1, and API 2SK (published in 1984, 1993, and 1995, respectively), and these codes continue to be applicable to the analysis and design of stationkeeping systems that are normally manned and may be occasionally evacuated. The design of mooring systems described herein assumes redundancy, intact and one-line broken cases satisfying the acceptance criteria are required, and therefore it is not applicable to moorings that cannot keep station in one-line broken conditions (such as single-line tethers for buoys or mooring systems with less than five mooring lines in the intact case). For permanent production systems, operating procedures for stationkeeping systems are intended, as a minimum, to include the ability to shut in wells and the facility in an emergency (e.g. emergency shut-down valves on the seabed); otherwise, the consequence of mooring failure could be very different than inherently assumed.

This edition includes several additions and changes. The most significant changes include the following:

- mandatory minimum design requirements are collected in the body of the standard, and informative guidance is included in Annex A;
- Gulf of Mexico hurricane season mobile offshore drilling unit mooring requirements are included in Annex B;
- guidance based on recent technical advances in the offshore industry is also included throughout.

The Fourth Edition of API 2SK also represents an umbrella document for stationkeeping system design, which is supported by additional guidance or specifications of stationkeeping system components, such as environmental criteria, anchor design, inspection, and integrity management. These supporting documents include (to address the described interest):

- API 2MET (environmental conditions a moored stationkeeping system is exposed to);
- API 2SM (determination of fiber rope properties for design analysis);
- API 2I (inspection of moored stationkeeping systems and components);
- ISO 19901-4 (geotechnical aspects of anchor designs for stationkeeping systems);
- API 2MIM (integrity management of moored stationkeeping systems);
- API 2F (chain specification for moored stationkeeping systems);
- API 9A (wire rope elements of a moored stationkeeping system);
- API 2S (mooring fairleads or windlasses for a moored stationkeeping system).

The technology of moored floating units continues to develop. In those areas where adequate data are available, specific and detailed recommendations are given. In other areas, general statements are used to indicate where it is intended for consideration to be given to those particular design aspects. Designers are encouraged to utilize research advances available to them.

Design and Analysis of Stationkeeping Systems for Floating Offshore Structures

1 Scope

This standard addresses the design and analysis of stationkeeping systems (mooring systems with or without thruster assistance) in conditions from survival to operational. Different design requirements for mobile and permanent moorings are provided.

The procedures for the design or site assessment of mobile mooring systems specified in this document are based on a deterministic approach where mooring system responses, such as line tensions, vessel offsets, and anchor loads, are evaluated for a design environment defined by an annual probability of occurrence or return period. Mooring system responses are then checked against acceptance criteria for mooring strength, offsets and orientation, clearances, anchor capacity, fatigue resistance, and so forth. The minimum acceptance criteria are either defined in this standard or are to be specified by the owner or the operator.

For moored vessels, system responses are calculated and compared to acceptance criteria for limit states describing acceptable extreme loads (line tensions), vessel offsets (translation and rotation), clearances (vessel, risers, water surface, seabed, anchors, field infrastructure, etc.), and fatigue (cumulative mooring component fatigue damage). Limit states associated with the extremes of the vessel's first order wave-frequency motions (surge, sway, heave, roll, pitch, and yaw at a particular point on the vessel), such as serviceability of machinery, heave compensators, separators, tank sloshing, motion-sickness, etc., exist; however, they are not addressed by this standard.

The requirements of this standard mainly address spread and single-point mooring systems with mooring lines composed of chain, wire rope, fiber rope, or a combination of these. This standard is applicable to the following types of stationkeeping systems:

- spread moorings;
- single-point moorings, anchored by spread mooring arrangements;
- thruster-assisted moorings (TAMs).

NOTE Guidance on the design and operation of dynamically positioned vessels is contained in IMCA M103.

This standard is not applicable to the vertical tendons found on tension-leg platforms (TLPs), which are covered by API 2T. Parts of this standard may not be appropriate for stationkeeping systems that are normally unmanned and occasionally manned (such as wind farms) or normally unmanned floating facilities. API 2SM, API 2I, and API 2MIM provide more detailed guidance on fiber ropes, mooring inspection, and integrity management.

2 Normative References

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

API Recommended Practice 2A-WSD, *Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design*

API Recommended Practice 2I, *In-Service Inspection of Mooring Hardware for Floating Structures*

API Recommended Practice 2MET, *Derivation of Metocean Design and Operating Conditions*

API Recommended Practice 2SM, *Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring*

ISO 19901-4 ¹, *Petroleum and natural gas industries: Specific requirements for offshore structures—Part 4: Geotechnical and foundation design considerations*

3 Terms, Definitions, Symbols, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

active stationkeeping system

Stationkeeping systems that make use of dynamic positioning (DP), thruster assistance, line length or pretension adjustments, planned changes in vessel draft, winching (kedging) off location, disconnection, etc.

3.1.2

catalog break strength

CBS

The manufacturer's design or target break strength for fiber rope (including terminations), wire, chain, or connecting hardware used in mooring lines, usually given in kilonewtons (kN), metric tons (tonne), or thousands of pounds (kip).

NOTE 1 Adapted from API 2SM.

NOTE 2 The minimum break strength (MBS) of a component is also used.

3.1.3

catenary mooring

Mooring system where the restoring force is mainly provided by the distributed weight of mooring lines.

NOTE Mooring system restoring forces are due to forces from both catenary and strain deformations of the mooring lines.

3.1.4

damaged condition

State of the stationkeeping system after a mooring line(s) breakage or a single-point failure of the thruster system or a combination of these.

3.1.5

design condition

design situation

A set of physical conditions within an annual probability of occurrence, or return period, used in evaluating the relevant limit states, one of the design load cases.

3.1.6

design criteria

Specific values or quantitative formulations that describe the conditions to be satisfied for each limit state.

NOTE The design criteria given in this standard are minimum requirements.

¹ International Organization for Standardization, Chemin de Blandonnet 8, CP 401, 1214 Vernier, Geneva, Switzerland, www.iso.org.

3.1.7**design service life**

Duration for which the structure or structural component is intended to be used, with planned maintenance (usually given in years).

3.1.8**dynamic load**

External load that induces acceleration of a structural component, normally specified by a spectrum, e.g. wind and wave spectra and associated parameters.

3.1.9**dynamic positioning****DP**

Stationkeeping technique in which onboard thrusters generate forces that counter vessel offsets and or environmental loads.

3.1.10**expected value**

The expected value of a probability distribution is a predicted value of the variable, calculated as the sum of all possible values each multiplied by the probability of its occurrence—also known as the expectation, mathematical expectation, mean, average, or first moment of the distribution.

3.1.11**floating structure**

Surface structure where the structure's weight and vertical forces due to mooring lines, risers, umbilicals, etc. are completely supported by its buoyancy.

3.1.12**integrated thruster control system****ITCS**

The integrated thruster control system (ITCS) consists of the thrusters and the control, power generation, and distribution systems.

3.1.13**limit state**

Limit states define the limiting conditions beyond which the structural system or component is no longer deemed to satisfy the design requirements; consequently, there is a correspondence between limit states and traditional design conditions.

3.1.14**minimum break strength****MBS**

The MBS is the component's strength as defined by a recognized industry standard.

NOTE It is also called the minimum break load (MBL), break test load, reference break strength (RBS), and catalog break strength (CBS).

3.1.15**mobile mooring system**

Mooring system, generally retrievable, intended for deployment at a specific location for a short-term operation, such as those for mobile offshore drilling units (MODUs).

3.1.16**mobile offshore drilling unit****MODU**

A floating structure that performs drilling operations.

NOTE One of the differences between MODU and mobile offshore unit (MOU) is that both operational and survival draft conditions need to be analyzed for a MODU but not MOU.

3.1.17**mobile offshore unit****MOU**

Structure that is frequently relocated to perform a particular function.

EXAMPLE Includes MODU, tender-assist vessel, pipe-laying vessel or barge, offshore construction structure, accommodation structure (floating hotel or floatel), service structure, or MODUs, etc.

3.1.18**mooring component**

A component used in mooring or anchoring a floating structure.

EXAMPLE Chain, steel wire rope, fiber rope, clump weight, buoy, winch, windlass, chain jack, stopper, tri-plate, H-links, shackles, fairlead, anchor, etc.

3.1.19**operator**

Representative of the company or companies that own or operate a development, who can be the operator on behalf of co-licensees.

EXAMPLE The operator owns the development, whereas the MODU is owned by the drilling contractor.

3.1.20**owner**

Representative of the company or companies that own a development or that own the floating structure.

3.1.21**passive mooring**

Passive moorings respond to changes in vessel draft, trim, and environmental loads without any intervention or adjustment of the mooring lines, do not use thrusters, and are not readily disconnectable.

3.1.22**permanent mooring system**

Mooring system normally used to moor floating structures deployed for long-term operations.

NOTE Such as those for a floating production system.

3.1.23**probability**

The relative frequency that an event will occur, as expressed by the ratio of the number of occurrences of the event to the total number of possible occurrences.

3.1.24**reliability**

A measure of the probability of an item or system to adequately perform a required function under stated conditions of use and maintenance for a stated period of time.

3.1.25**resistance****strength**

Capacity of a structure or component to withstand load effects without failure.

EXAMPLE Component strength (kN, tonne, or kip) or fatigue resistance (component T-N fatigue curve).

3.1.26**return period**

The return period, in years, is equal to the reciprocal of the annual probability of occurrence of a single event, or the joint probability of occurrence of multiple events.

3.1.27**riser**

Tubulars used for the transport of fluids between the sea floor and the platform.

NOTE Possible functions include drilling, well intervention, production, injection, subsea systems control, and export of produced fluids.

3.1.28**risk**

The product of the probability of occurrence of a hazardous event and its consequence(s).

3.1.29**semisubmersible**

Floating structure normally consisting of a deck structure with a number of widely spaced, large cross-section, supporting columns connected to submerged pontoons.

NOTE Pontoon and column geometry is usually chosen to minimize global motions in a broad range of wave frequencies.

3.1.30**significant value**

Statistical measure of a zero-mean random variable equal to twice the standard deviation of the variable.

NOTE It has the same dimensional properties as the variable being examined.

3.1.31**single-point mooring**

Mooring system that allows the floating structure to which it is connected to vary its heading.

EXAMPLE One example of a single-point mooring is a turret mooring system where a number of mooring lines are attached to a turret, which includes bearings to allow the structure to rotate.

3.1.32**spar**

Deep-draught, small water-plane area floating structure.

3.1.33**spread mooring**

Mooring system consisting of multiple mooring lines terminated at different locations on a floating structure, extending outward, and providing an almost constant vessel heading.

3.1.34**stationkeeping system**

System capable of limiting the excursions of a floating structure within prescribed limits.

3.1.35**thruster-assisted mooring****TAM**

Stationkeeping system consisting of both mooring lines and thrusters.

3.1.36**tropical revolving storm****TRS**

Collective name for hurricanes, cyclones, and typhoons.

3.1.37**virtual mass and inertia**

The sum of mass and added hydrodynamic mass or inertia and added hydrodynamic inertia.

NOTE Also called effective mass and inertia.

3.2 Symbols

D	annual fatigue damage, in years ⁻¹
d	diameter of the mooring line or component, in millimeters (mm) or inches (in.)
K	fatigue constant for T-N curves, nondimensional
K_S	fatigue constant for S-N curves; K_S has dimension of S^{m_s} , where S is stress and m_s is the slope of the S-N curve
L	design services life, in years (yr)
m	slope of the T-N fatigue curve
m_s	slope of the S-N fatigue curve
N	number of cycles, nondimensional
N_i	number of cycles to failure at normalized tension range i (from appropriate T-N curve)
n_i	number of cycles per year within the tension range interval i
P_i	probability of occurrence of environmental state i
R	ratio of tension range to reference break strength at half of the component's design life, nondimensional
T	specified storm period, in seconds (s)
T_i	time spent in environmental state i per year, in seconds (s)
v_i	zero upcrossing frequency of the tension spectrum in environmental state i , in hertz (Hz)

3.3 Acronyms and Abbreviations

AHC	anchor holding capacity
AJP	annual joint probability of occurrence
CALM	catenary anchor leg mooring
CBS	catalog break strength
CFD	computational fluid dynamics
DP	dynamic positioning
ELBS	end-of-life break strength
FEA	finite element analysis
FMEA	failure modes and effects analysis
FPSO	floating production, storage, and offloading structure or system
FSO	floating storage and offloading structure or system
HMPE	high-modulus polyethylene
IPB	in-plane bending
ITCS	integrated thruster control system

JIP	joint industry project
MBL	minimum break load
MBS	minimum break strength
MODU	mobile offshore drilling unit
MOU	mobile offshore unit
MPM	most probable maximum
NPD	Norwegian Petroleum Directorate
OD	operator defined
OPB	out-of-plane bending
ORQ	oil rig quality
RAO	response amplitude operator
RBA	response-based analysis
RBS	reference break strength
RRP	required (shall), recommended (should), or permitted (may or can)
SCF	stress concentration factor
SEPLA	suction embedded plate anchor
SWF	single worst failure
TAM	thruster-assisted mooring
TLP	tension-leg platform
VIM	vortex-induced motion
VLA	vertically loaded anchor

4 Stationkeeping Systems and Components

4.1 Mooring Components

4.1.1 General

The mooring components shall be specified or approved by the owner or the operator. Manufacturing of mooring line components should be subject to quality assurance standards, as specified by the owner or the operator.

Mooring components are used to connect the moored floating structure to the seafloor and can be categorized as tensioning equipment, fairleads and bending shoes, padeyes, mooring line segments including terminations, connecting hardware, buoys, weight chain, clump weights, and anchors.

4.1.2 On-vessel Tensioning Equipment

The tensioning equipment shall be designed for a load equal to the MBL of the mooring line they are connected to; this includes, for example, but not limited to, stoppers, fairleads, padeyes, and their structural foundations.

For tensioning operations, winches and chain jacks may be designed to the loads under which they will be operated. The design philosophy is based on mooring line components failing before the foundations fail.

The analysis and design of fairleads, bending shoes, padeyes, and stopper arrangements should include effects in addition to tension-tension loading on the wear and fatigue performance of the mooring line components.

Winches should be designed to ISO 9089. The foundation of the tensioning equipment on the floating structure should be designed to API 2A-WSD and API 2FPS.

Tensioning equipment, such as winches, windlasses, and chain jacks, should be maintained according to API 2S or API 2MIM.

4.1.3 Fairleads and Bending Shoes

For fairleads, chain links are supported in pockets, and wire ropes are supported in a shaped channel. Poor support conditions or poor geometric fit between chain or wire rope and the fairlead may result in a reduction in the strength and fatigue endurance of the component.

Bending shoes may be made of a curved plate or of a number of flat plates with angular discontinuities (knuckles) between the plates. Also, the bending shoe may contain a groove, in which case every other link is horizontal with both side bars resting on the plate and the intermediate links are vertical in the groove. The complex loading of the links on the bending shoe may result in the reduction of their strength and fatigue life.

4.1.4 Off-vessel Anchor Line Components

4.1.4.1 General

Mooring line off-vessel components consist of, but are not limited to, fiber ropes, steel wire ropes, chains, connectors, buoys, clump weights, weight chain, and anchors.

NOTE See Section 7 for anchors; in addition, recommendations for geotechnical surveys and the design of some types of anchors are provided in ISO 19901-4.

4.1.4.2 Fiber Rope

Mooring system requirements, analysis methods, and the acceptance criteria for fiber ropes are the same as for steel components. For fiber rope properties, construction, and testing, see API 2SM.

4.1.4.3 Mooring Wire Rope

Wire ropes and end sockets should be manufactured to meet or exceed the requirements of one of the following specifications:

- a) owner- or operator-specified manufacturing and testing specifications, or
- b) API 9A.

4.1.4.4 Mooring Chain

Mooring chain should be manufactured to meet or exceed the requirements of one of the following specifications:

- a) owner- or operator-specified manufacturing and testing specifications,
- b) API 2F, or
- c) ISO 20438:2017.

4.1.4.5 Connecting Hardware

Connecting hardware consists of standard components (e.g. D-shackles, H-links, etc.) or components specially designed for a particular application. Design, manufacturing, and functional requirements shall be specified by the owner or the operator. Multiyear drilling campaigns may require fatigue assessment of mooring components, particularly connecting hardware. Be aware that Kenter links commonly used in MODU mooring systems are not suitable for long-term mooring services.

Standard connecting links should be made of forged or cast material and should be compatible with the connected chain or terminations of the wires or fiber ropes in terms of strength, fatigue, and corrosion protection requirement. Kenter links should meet the requirements specified in API 2F or ISO 20438:2017.

Specially designed mooring connectors, such as H-links, subsea mooring line connectors, single- or dual-axial hawse pipes, etc., shall satisfy the strength and fatigue requirements in this standard.

4.1.4.6 Buoys

Surface buoys should incorporate measures (such as compartmentalization) to minimize the risk of sinking in the event of damage. Subsurface buoys of steel construction shall be designed for external pressure to a pressure containment standard for use at the maximum operational depth identified by the mooring analysis; see 7.3.6.3 for specific information regarding the requirements.

Steel buoys should be provided with a corrosion protection system.

4.1.4.7 Disconnectable Turret Buoy

Turret buoys are used on floating production, storage, and offloading structures or systems (FPSOs) with disconnectable turrets. The net buoyancy of the buoy should be adequate to support the risers, umbilicals, and mooring lines during and after disconnection. The mooring and riser loads and the net buoyancy should be designed so that when released the buoy's motions do not result in clashing of the mooring lines and/or risers or unacceptable seabed contact.

4.2 Monitoring Equipment

4.2.1 General

For regions where vessels are evacuated during extreme environmental conditions, such as for tropical revolving storms, remote monitoring should be implemented with data uploaded in real time. See Annex B and API 2MIM.

4.2.2 Line Tension, Payout, and Vessel Position

If the operation of the floater requires mooring line adjustment, line tensions and line payout shall be continuously displayed at the winch and in the control room. Passive mooring systems should be equipped with a monitoring system that at a minimum displays and records vessel position, heading, and draft.

Where vessel position information is critical to operations, the position reference system(s) shall provide redundancy.

5 Environmental and Site Data

5.1 General

Design and site-assessment of station keeping systems shall account for the normal and extreme wind, sea-wave, swell-wave, and current conditions.

For a mooring system subject to ice loading, design recommendations are provided in API 2N.

5.2 Site-specific Data Requirements

5.2.1 General

The joint probabilities of wind, sea-wave, swell-wave, and current intensities and directions should be evaluated in the development of metocean criteria for normal and extreme conditions.

5.2.2 Environmental Data

Environmental data shall be collected and analyzed in conformance with API 2MET. The interaction of environmental phenomena, such as wind, waves, current, and tide, is site specific. The joint probabilities of wind, sea-wave, swell-wave, and current intensities and directions should be considered in the development of metocean criteria for normal and extreme conditions.

Some areas are subject to transient conditions, such as squalls, or to occasional high currents, such as solitons. In these cases, the occurrences should be accounted for in determining the relevant environmental design conditions.

For fatigue analyses, weather bins of sea-wave, swell-wave, wind, current intensities, and global directions should be developed to support the mooring analyses. Multiyear hindcasts of wind, sea-wave, swell-wave, and current conditions may be provided for direct use in the fatigue analyses.

5.2.3 Seabed Map, Bathymetry, and Soil Profile

The field bathymetry map over the extent of the mooring line and riser touchdown points, and anchor locations should be provided. Seabed structures, hazards, or restricted zones, if any, shall be provided on field charts or maps.

Seabed soil conditions shall be investigated for the intended site to provide data for the anchoring system design. The sea floor slope shall be properly accounted for in the mooring analysis, when relevant. For permanent moorings, seabed surveys shall be performed in sufficient detail to obtain data representative of each proposed anchor installation target area. Refer to ISO 19901-4 and ISO 19901-8 for more detailed guidance.

5.2.4 Wave Statistics

Site-specific (hindcast) data requirements for sea and swell-waves should account for the following:

- a) wave height versus wave period;
- b) wave height versus wave direction relationships;
- c) wave spectrum and associated parameters.

5.2.5 Wind Statistics

Site-specific data requirements should account for the following:

- a) wind speed, averaging time, and reference height;
- b) wind direction;
- c) wind profile;
- d) wind spectrum or time history for transient winds.

5.2.6 Current Statistics

Site-specific data requirements should account for the following:

- a) current speed;
- b) current direction;
- c) current profile;
- d) current spectrum (when applicable).

6 Design and Site Assessment of Stationkeeping Systems

6.1 General

The purpose of passive or active stationkeeping systems is to restrict the excursion of the floating structure within prescribed limits and to provide heading control when the structure's orientation is important for operations or safety. Not all system responses can be controlled or restricted by the stationkeeping system (e.g. wave-frequency vessel motions are generally insensitive to the stationkeeping system).

Design and site assessment of stationkeeping systems shall account for the type of system, which include:

- a) mobile and permanent systems, and
- b) passive and active (disconnectable, TAM, and MOU) systems.

The design or service life of permanently moored facilities is typically in the 15-year to 30-year range. Unless designed for disconnection, permanent stationkeeping systems shall be designed for full year metocean conditions (full populations of all types) without disconnection of risers. MOUs themselves typically have a design life of 30 or more years; however, they may be on a particular location for only a few weeks or months. Consequently, an MOU site assessment may be based on seasonal metocean conditions (e.g. MOU operations may be planned to avoid the winter storm season or tropical revolving storm season).

For mobile moorings where the consequences of a stationkeeping failure cannot be mitigated by suspending operations and moving to the survival condition (e.g. mooring in close proximity to a permanent facility), a risk assessment should be used to determine the appropriate environmental return period [i.e. inverse of the annual joint probability of occurrence (AJP)], for the operation.

Mobile and permanent stationkeeping systems may be passive or active, or may occasionally require active intervention, such as line length management of a mooring system with fiber rope segments.

Passive mooring systems do not make use of thrusters to assist in keeping station, are not readily disconnectable, and typically do not adjust outboard mooring line lengths once the lines are deployed and pretensioned (i.e. passive systems respond to changes in vessel draft, trim, and environmental loads without any intervention or adjustment of the mooring lines). For some permanent mooring systems, outboard line lengths may not be readily adjustable (e.g. where the lines are terminated at padeyes).

Active stationkeeping systems make use of some of the following:

- DP;
- TAM;
- line length or pretension adjustments for different operational modes [e.g. step tensioning to reduce vortex-induced motion (VIM) response, or MODUs changing from operational to survival condition, or to reduce flex joint angle during drilling operations, etc.];
- planned changes in vessel draft in preparation for extreme conditions and/or evacuation;
- disconnection of the mooring lines from the vessel (e.g. for sea-ice or tropical revolving storms).

Mobile mooring or stationkeeping systems are commonly active systems. For example, during drilling operations MODUs typically ballast to a deep draft with high pretensions and may winch off-center to a safe zone while transferring loads, running casing, etc. When preparing for storm conditions, MODUs will typically disconnect and hang off or retrieve the drilling riser, de-ballast to increase airgap, reduce pretensions, and may or may not evacuate some or all personnel. For MODUs, these two vessel and mooring conditions are referred to as the *operating* and *survival* conditions. For MOUs, the consequences of a stationkeeping failure for *operating*, *standby*, and *survival* conditions can be very different. Offset limits associated with the *operating* or riser connected conditions are also different from those associated with the storm *survival* condition. Similarly, different acceptance criteria may also apply to MOUs used for tender assistance, accommodation, diving support, construction, pipe-laying, etc., depending upon the proximity to other structures and the operation being performed. It is important that the MODU operational mooring analysis assumptions for rig position management through active winching match the rig operating procedures and riser operability analysis assumptions regarding offset limit management.

Mobile moorings may be operated in different modes (e.g. operating, standby, or survival) with varying levels of consequences of failure. Typically, operations with high consequences are performed in mild environmental conditions and operations are suspended in severe weather, so that the consequences of a stationkeeping failure are reduced in extreme environmental conditions that result in extreme responses, offsets, tensions, anchor loads, etc.

Line length adjustments during extreme environmental events shall not be considered in the stationkeeping analysis. If operating practice and procedures for improving mooring performance, such as slackening leeward lines or slackening all mooring lines, before severe weather and/or evacuation is established, it can be taken into consideration in the stationkeeping analysis.

The acceptance criteria in this standard assume that the risers of permanent stationkeeping systems are equipped with emergency shut-in valves that allow the risers to be shut in and possibly purged (e.g. in advance of disconnection or prior to evacuation).

6.2 Design Conditions

6.2.1 General

The methodology for the design or site assessment of mobile mooring systems in this document is based on performing mooring system analyses and comparing specific mooring system responses, with acceptance criteria defined in this document or specified by the owner or the operator. IMCA M103 and ISO 19905-3 provide design and operational guidance for DP systems.

For moored vessels, system responses are calculated and compared to acceptance criteria for:

- Strength—Mooring component strength for intact and damaged conditions. Herein the ultimate limit state includes both intact and damaged stationkeeping systems.
- Serviceability—Vessel offset, orientation, and clearance constraints. For mooring components these constraints include clearances with the vessel, risers, seabed, water surface, field infrastructure, exclusion zones, etc.
- Fatigue—Cumulative mooring component fatigue damage.

System properties, such as wind, current, and wave forces and moment coefficients, wave motion response amplitude operators (RAOs), virtual mass and inertia, mooring line pretensions, mooring system stiffness, mean equilibrium position, etc., all depend on the vessel's draft and trim. The range of the vessel's draft, trim, and in some cases heel, shall be accounted for in the stationkeeping analyses. For FPSOs, where the range of operating drafts and trims is significant, the design analysis cases should be performed for minimum, mid, and maximum operating drafts and trims. For MODUs, mooring line pretensions and vessel

drafts are often different for operating, standby, and survival conditions. For site assessment of MODU stationkeeping systems, the survival and operating cases shall be analyzed using the appropriate vessel draft, vessel properties, and mooring line pretensions.

NOTE An example of analysis cases and acceptance criteria for a permanent system's mooring line strength and seabed clearance is illustrated in Table A.1, and an example for a site assessment of a mobile mooring is illustrated in Table A.2.

The analysis cases for the design of permanent and site assessment of mobile systems are described and summarized in Table 1 through Table 5. The acceptance criteria are in Section 7, and methods of analysis and analysis requirements are in Section 8.

For both mobile and permanent stationkeeping systems, the environmental parameters describing extreme return period, normal operating, and fatigue conditions shall be developed from site-specific metocean data. Metocean conditions for extreme N-year return period conditions are defined as those combinations of wind, waves, and currents with an AJP of $1/N$. This is often approximated using multiple sets of conditions, for example:

- N-year wind with associated sea-waves, currents, and swell-waves;
- N-year sea-waves with associated winds, currents, and swell-waves;
- N-year currents with associated wind, sea-waves, and swell-waves;
- N-year swell-waves with associated winds, sea-waves, and currents.

The most severe directional combination of wind, sea-wave, current, and swell-wave for the response being investigated shall be selected for the design or site assessment of the stationkeeping system, consistent with the site's environmental conditions (see A.6.2). For turret moored vessels in transient wind squall conditions, the directional combinations shall include initial vessel heading and wind squall direction consistent with the site-specific metocean conditions (see 8.6.3).

For some mooring systems or types of system response, the most onerous response(s) may not be associated with the maximum environmental return period, for example:

- mean wave drift forces and low-frequency vessel motions increase with decreasing wave period, consequently the N-year return period wave condition may not yield the most onerous responses (maximum tensions, offsets, minimum clearances, etc.) with an annual probability of occurrence of $1/N$ or greater;
- for spars and semi-VIM lock-in maximum responses may occur for current speeds below the N-year return period current speed (for a specific design, model test data are needed to determine reduced speed range for lock-in responses);
- for an external turret moored vessel, clearances between the mooring lines and vessel are usually smallest in benign metocean conditions, whereas for MODUs, mooring line contact with the anchor bolster is most critical for slack lines in extreme environments.

In this standard where an N-year return period metocean condition is specified, this shall include all metocean conditions up to and including N-year return period conditions (return periods $\leq N$ -years), or more generally all conditions with an AJP greater than or equal to $1/N$ ($AJP \geq 1/N$).

NOTE The calculation of the joint annual probability of simultaneous occurrence of two independent events is described in A.6.2.

It is recommended that stationkeeping analyses be performed for metocean conditions with a range of return periods that span the required return period. For example, MOU or permanent mooring's strength analyses may be performed for return period conditions of 1, 5, 10, 25, 100, and 200 years to ensure that the most onerous conditions are identified and to provide a better understanding of system responses and trends.

Where there is a concern that the (deterministic) design approach in this standard is inappropriate for the specific system, a response-based analysis (RBA) may be used. If RBA is performed, the methodology (development of the metocean dataset used as input and the statistical postprocessing of system responses) shall be specified by the owner or the operator (see A.8.8). The acceptance criteria for tension, offset, and clearance provided in Section 7 shall still be satisfied.

6.2.2 Strength Analysis Cases

6.2.2.1 Strength Analysis Cases for Permanent Systems

Analysis cases for the evaluation of the intact and damaged strength of passive and active permanent stationkeeping systems are listed in Table 1. Analyses shall be performed for vessel drafts and trims that span the operating range of the vessel.

Passive permanent mooring systems [part (A) of Table 1] shall satisfy the strength criteria of Section 7 for intact and one-line broken cases, for metocean conditions with return periods up to and including 100 years.

TAM permanent systems that are not also disconnectable mooring systems [part (B) of Table 1] shall satisfy the strength criteria, Section 7, for intact and single-failure cases for metocean conditions with return periods up to and including 100 years. For TAM systems, definitions of intact and damaged conditions are given in 7.1.1.

Disconnectable permanent mooring systems, with or without thruster assistance, shall be analyzed for two conditions, with the vessel connected [part (C.1) of Table 1] and the vessel disconnected [buoy alone, part (C.2) of Table 1], respectively. With the vessel connected, the stationkeeping system shall satisfy intact and single-failure (mooring line or thruster) strength criteria, Section 7, for metocean conditions up to and including the maximum vessel connected environmental condition. For example, where a permanent mooring system will only disconnect for ice conditions, the maximum connected environment shall include 100-year return period metocean conditions. Where the vessel will disconnect for tropical revolving storms, the maximum connected environment is the 100-year return period environment excluding tropical revolving storm conditions. Where it may not be possible to disconnect for sudden hurricanes, the 100-year sudden hurricane criteria should be considered. Intact and damaged strength analyses shall also be performed for the buoy alone [vessel disconnected, part (C.2) of Table 1] for metocean conditions up to and including 100-year return period conditions.

Table 1—Strength Analysis Cases: Permanent Systems

Permanent Systems—Analysis Cases	Annual Joint Prob. or Return Period ^a	RRP	Comment
(A) Strength, Passive Mooring			
Intact mooring	10^{-2} , 100 yr	Required	Return periods up to and including 100 yr
One line broken	10^{-2} , 100 yr	Required	Return periods up to and including 100 yr
Robustness and System Behavior			
Two lines broken	OD	Permitted	Weather conditions and risk assessment for producing with one line broken
Intact mooring	OD	Permitted	Change in response (VIM, wave in deck, etc.) risk assessment (e.g. $AJP \geq 10^{-4}$)
Hull compartment damage	OD	Permitted	Special case as needed (e.g. $AJP \geq 10^{-2}$)
(B) Strength, Thruster-assisted Mooring			
Intact system	10^{-2} , 100 yr	Required	Return periods up to and including 100 yr
Single failure (mooring, thruster)	10^{-2} , 100 yr	Required	Return periods up to and including 100 yr
Robustness and System Behavior			
Double failures (mooring, thruster)	OD	Permitted	Weather conditions and risk assessment for producing with one line broken
Intact system	OD	Permitted	Change in response (VIM, wave in deck, etc.), risk assessment (e.g. $AJP \geq 10^{-4}$)
Thruster blackout	OD	Permitted	Risk assessment (e.g. $AJP \geq 10^{-2}$)
Hull compartment damage	OD	Permitted	Special case as needed (e.g. $AJP \geq 10^{-2}$)
(C.1) Strength, Disconnectable Mooring—Vessel Connected			
Intact system, vessel connected	Max connected env.	Required	Max connect env., $AJP \geq 10^{-2}$
Single failure (mooring, thruster), vessel connected	Max connected env.	Required	Max connect env., $AJP \geq 10^{-2}$
Robustness and System Behavior			
Double failures (mooring, thruster), vessel connected	OD	Permitted	Weather conditions and risk assessment for producing with one line broken
Intact system, vessel connected (fail to disconnect)	OD	Permitted	Risk assessment (e.g. $AJP \geq 10^{-4}$)
Hull compartment damage	OD	Permitted	Special case as needed (e.g. $AJP \geq 10^{-2}$)
(C.2) Strength, Disconnectable Mooring—Buoy Alone, Vessel Disconnected			
Intact system, buoy, vessel disconnect	10^{-2} , 100 yr	Required	Return periods up to and including 100 yr
One line broken, buoy, vessel disconnect	10^{-2} , 100 yr	Required	Return periods up to and including 100 yr
Transient analysis, response of buoy on disconnecting	OD	Permitted	Risk assessment, mooring line and riser clashing, etc. (max disconnect env.)
^a OD is operator defined. NOTE The colors are only intended to make it easier to the user to identify the respective parts of the table.			

All load-bearing components of the mooring system shall satisfy the acceptance criteria of Section 7 (i.e. at anchors, fairleads, stoppers, end points of each mooring line segment, connectors, buoys, clump weights, etc., where applicable). For mooring lines that include buoys, clump weights, or loop/weight chains, the loss due to disconnection from the mooring line without the failure of the line itself shall be included as a potential damaged mooring line scenario.

To develop a more complete understanding of the performance of the stationkeeping system, the owner or the operator may perform analyses for some of the additional optional or permitted cases in Table 1. For example, knowledge of the stationkeeping systems' performance with two failures (mooring lines or thrusters) is necessary for evaluating risks associated with restarting production with one line failed.

6.2.2.2 Strength Analysis Cases for Mobile Systems

Analysis cases for the strength of intact and damaged mobile stationkeeping systems are listed in Table 2. Analyses shall be performed for the vessel drafts and pretensions applicable for operating, standby, and survival modes. Site-specific assessment criteria for MODUs operating in the Gulf of Mexico during hurricane season, June 1 to November 30, shall be as specified in Annex B.

The consequences of a failure to keep station depend upon the proximity of the moored system to other surface and subsea structures and environmentally sensitive areas, such as reefs and seafloor habitats; this is implicit in the types of MOU operations distinguished in Table 2, where:

- Away from other structures means negligible risk of hitting other structures during progressive failure of the mooring system, nominally greater than 25 miles [see part (A.1.1) of Table 2].
- In vicinity of other structures means possibility of hitting other structures during progressive failure of the mooring system, nominally greater than 1 mile [see part (A.1.2) of Table 2].
- In close proximity to other structures means likely (finite probability) to hit other structures during progressive failure of the mooring system (TAD, floatel, gangway connected), nominally less than 1 mile [see part (A.1.3) of Table 2]. This type of risks includes drifting MOU colliding with a fixed or floating platform, or dragging an anchor or a broken mooring line over a subsea asset.

Passive and TAM systems shall satisfy the strength criteria (Section 7) for intact and single-failure cases (Table 2) for metocean conditions with return periods up to and including 5, 10, and 25 years where they are away from, in the vicinity of, or in close proximity to other structures.

Disconnectable mobile mooring systems, with or without thruster assistance, shall be analyzed with the vessel connected to the mooring system for intact and single-failure cases for the maximum connected environmental conditions. For example, where a MODU mooring system will only disconnect for ice conditions, the maximum connected environment shall include 5-, 10-, or 25-year return period conditions, depending on whether or not the mooring is away from, in the vicinity of, or in close proximity to other structures. Where the vessel will disconnect for hurricanes, including sudden hurricanes, the maximum connected environment is the 5-, 10-, or 25-year return period conditions, excluding tropical revolving storm conditions, depending on whether or not the mooring is away from, in the vicinity of, or in close proximity to other structures. See Section 7 for acceptance criteria.

All of the components of the mooring system shall satisfy the acceptance criteria (i.e. tension or load limits at anchors, fairleads, stoppers, end points of each mooring line segment, connectors, buoys, or clump weights, etc.), where applicable. For mooring lines that include buoys, clump weights, or loop/weight chains, the loss of these components due to disconnection from the mooring line without the failure of the line itself shall be included as a potential damaged mooring line scenario.

For MOU deployment longer than a few weeks, additional guidance can be found in A.6.1.

Table 2—Strength Analysis Cases: Mobile Systems

Mobile Systems Analysis Cases	Passive and TAM	Disconnectable Mooring System	RRP	Comment
	Annual Joint Prob. or Return Period ^a			
(A) Strength, Survival Conditions				
(A.1.1) Away from Other Structures				
Intact system	2×10 ⁻¹ , 5 yr	Max connected env.	Required	—
Single failure (mooring, thruster)	2×10 ⁻¹ , 5 yr	Max connected env.	Required	—
(A.1.2) In the Vicinity of Other Structures				
Intact system	10 ⁻¹ , 10 yr	Max connected env.	Required	—
Single failure (mooring, thruster)	10 ⁻¹ , 10 yr	Max connected env.	Required	—
(A.1.3) In Close Proximity to Other Structures				
Intact system	4×10 ⁻² , 25 yr	Max connected env.	Required	Gangway disconnected in survival or standby mode
Single failure (mooring, thruster)	4×10 ⁻² , 25 yr	Max connected env.	Required	Gangway disconnected in survival or standby mode
Transient response after first failure (mooring, thruster)	OD	OD	Permitted	Special case as needed
(A.2) Robustness and System Behavior				
Double failure (mooring, thruster)	OD		Permitted	Risk assessment
Intact mooring and blackout	OD, TAM only	—	Permitted	Informative, system performance, risk assessment
Intact system and failure to disconnect	—	OD	Permitted	Informative, system performance, risk assessment
Intact system	OD, large return periods	—	Permitted	Informative, system performance, risk assessment
(B) Strength, Operating Condition				
Intact system	OD. Max operating env.	OD. Max operating env.	Required	Required for riser and clearance analyses, etc.
Single failure (mooring, thruster)	OD. Max operating env.	OD. Max operating env.	Required	Required for riser and clearance analyses, etc.

^a OD is operator defined.

NOTE The colors are only intended to make it easier to the user to identify the respective parts of the table.

6.2.3 Offset Analysis Cases

Analysis cases for permanent or mobile vessel offsets for intact and damaged stationkeeping systems are listed in Table 3. Analyses shall be performed for vessel drafts and pretensions applicable for the permanent or mobile system as described in 6.2.2.

Table 3—Offset Analysis Cases: Permanent and Mobile Systems

Analysis Case	Permanent Systems	Mobile Drilling (MODU)	Tender Assist or Close Proximity (Riserless)	RRP
	Annual Joint Probability or Return Period ^a			
Intact system	Intact riser offset limits, AJP 10 ⁻² , RP 100 yr	Offset limit for the maximum riser connected drilling (rotating) environment, OD	Offset limit for the maximum gangway connected environment, vessel to platform clearance, etc., OD	Required
Single failure (mooring, thruster)	Single-failure riser offset limits, AJP 10 ⁻² , RP 100 yr	Offset limit for the maximum riser connected nondrilling (nonrotating) environment, OD	Offset limit for the maximum gangway connected environment, vessel to platform clearance, etc., OD	Required

^a OD is operator defined.

For MOUs, the serviceability offset limit state is associated with the maximum environmental conditions for which the operations (riser connected, gangway connected, divers in water, laying pipeline, etc.) can be performed. These limiting environmental conditions will control the amount of time that is spent waiting on weather and therefore have a direct impact on the economics of the operation. Vessel offset analysis cases and acceptance criteria applicable for other types of MOU operations (such as diving support, construction, pipe-laying, etc.) shall be specified by the owner or the operator.

6.2.4 Clearance Analysis Cases

Analysis cases for assessing clearances of intact and damaged permanent and mobile mooring systems are listed in Table 4 and apply to the deployed (installed and pretensioned) mooring system, installation criteria and considerations are addressed in 6.3 and 10.2. Analyses shall be performed for vessel drafts and pretensions applicable for permanent and mobile systems as described in 6.2.2.

Fiber and steel wire ropes and their terminations may be damaged by repeated contact with the seabed. The recommended analysis cases to determine minimum clearances between wire and fiber ropes and the seabed [part (A) of Table 4] apply to the slack mooring lines, in particular the bottom end of the wire or fiber rope segment in the water column [i.e. wire or fiber ropes in the water column that are on the slack side of the mooring system that could contact the seabed (be located in the thrash zone)]. Wire ropes may be in contact with the seabed provided that the contact remains throughout the full range of predicted line tensions (i.e. the wire or fiber rope does not slide on or lift off the seabed). The susceptibility to damage of a fiber rope due to seafloor contact depends on the design of the rope's jacket and filter barrier, and the soil conditions and seafloor characteristics. Also, as fiber ropes are close to neutrally buoyant, or slightly negatively buoyant, they are susceptible to movement and possible damage on the seafloor. Requirements for rope construction, seabed survey, and soil conditions are specified in API 2SM for fiber ropes in contact with the seabed.

For fiber moorings, a suitable length of steel wire or chain should be provided at the top end of the fiber rope mooring leg. The upper steel mooring line segment can be used to adjust the mooring line tension as needed to allow for rope elongation throughout the mooring system's life, or for repositioning of permanent or mobile vessels. It is recommended that the owner or the operator establish clearance requirements between the top of the fiber rope and the sea surface [part (B) of Table 4].

For external turret moored vessels, the clearance between the mooring lines and vessel are usually smallest in benign metocean conditions when the vessel's orientation places it over a line or group of lines, and clearances generally increase with the severity of the environment. For external turret moorings contact of taut lines with the hull shall be avoided in metocean conditions up to and including 1-year return period conditions [part (C) of Table 4]. The calculation of the minimum clearance between the hull and mooring

line shall be performed for the most onerous combination of vessel draft and trim and include the effects of low- and wave-frequency vessel motions.

For other types of permanent moorings and MOUs, clearances between the mooring line and hull or anchor bolster are generally a minimum for slack lines in extreme environmental conditions. For permanent systems, slack side mooring lines shall remain clear of the hull in the intact conditions specified in 6.2.2. For permanent systems, slack mooring lines should remain clear of the hull in the single-failure conditions specified in 6.2.2. For MOUs, the owner/operator may define the return period and clearance requirements for slack side mooring lines. Clearance analysis cases for slack lines of permanent and mobile moorings in intact and damaged stationkeeping systems are contained in Table 4.

Mooring lines shall remain clear of risers, mooring lines of other installations, pipelines, seabed infrastructure, and exclusion zones [part (D) of Table 4] in the intact conditions specified in 6.2.2. Mooring lines should remain clear of risers, other mooring lines, pipelines, seabed infrastructure, and exclusion zones in the single-failure conditions specified in 6.2.2.

Surface and subsurface buoys may be used in intact and damaged cases to manage clearances where a mooring line crosses over a pipeline, another installation's mooring line, or to maintain clearance between the line and the hull or anchor bolster. Analyses shall be performed to calculate the maximum submergence of a surface buoy or maximum depth below the water surface of a subsurface buoy, as specified in part (E) of Table 4.

The failure of a buoy, clump weight, or loop/weight chain due to disconnection from the mooring line or loss of buoyancy, without the failure of the line itself, will impact clearances and mooring system performance. The owner or the operator should evaluate the effects of the loss of a buoy, loop/weight chain, or clump weight on clearances and mooring system performance, and where necessary introduce redundancy or other measures to mitigate the consequences of losing buoyancy, weight chain, or clump weight.

The owner or the operator shall assess the impact of trenching on the integrity of the mooring system. The depth, width, and length of trenches created by the mooring line's motion at the line's touchdown point depend on the type of soil and the magnitude of line's motions (kinetic energy) in normal or daily environmental conditions. The degradation rate of the mooring chain (side-bar abrasion and interlink wear) also depends on the line's motions and soil conditions. Similarly, other types of mooring components (wire and fiber rope) and risers will be damaged by soil excavation and trenching.

In shallow water, the depth of the trench may significantly increase the mooring system's total vertical load on the vessel. For floating structures with small water-plane areas, such as catenary anchor leg mooring (CALM) buoys, the increase in vertical load may in turn result in a significant loss of freeboard. The design should allow for the potential increase in vertical mooring and riser loads due to the formation of trenches over the field life of the system.

Trenches that develop close to the anchor can reduce the anchor holding capacity (AHC). See ISO 19901-4 for estimating AHC of various anchor types. Design methods and codes for predicting the depth and width of a trench near to the anchor at the end of field life, and for evaluating the AHC in the presence of the trench are not presently available. However, the mooring system may be designed with a length of mooring line adjacent to the anchor in contact with the seabed, so that the distance between the trench and the anchor (proximity) does not reduce the AHC. Analyses for the case where the distance between the trench and the anchor is sufficient to ensure that the AHC is not reduced are specified in part (F) of Table 4 and discussed in 7.3.7 and 8.6.4. Other methods to mitigate trenching risk on anchor at design stage include assessment of seabed erodibility potential, inverse catenary analysis, and periodic inspection requirements. Clearances between installed anchors and pipelines, other installation's mooring lines, seabed assets, and exclusion zones are specified in Section 7. Anchor clearances are based on two considerations, whether the AHC is greater or less than the mooring line's break strength, and the direction of potential anchor dragging with respect to seabed infrastructure and exclusion zones [part (G) of Table 4]. For MODUs operating in the Gulf of Mexico during hurricane season, anchor clearance requirements are provided in Annex B.

Table 4—Clearance Analysis Cases: Permanent and Mobile Systems

Analysis Case	Type of Clearance and/or Environmental Conditions	Permanent		Mobile	
(A) Clearance, Mooring Line with Seabed (Thrash Zone)		RRP	Comment	RRP	Comment
Intact system (mooring, thruster)	Wire rope remains clear of seabed in environments up to intact design return period (see Tables 1 and 2)	Recommended	—	Permitted	Informative
Intact system (mooring, thruster)	Fiber rope remains clear of seabed in environments up to intact design return period (see Tables 1 and 2)	Required	—	Recommended	Depends on seabed conditions
Single failure (mooring, thruster)	Limiting environments for wire or fiber rope to remain clear of seabed	Permitted	Informative, producing with single failure	Permitted	Informative
Double failure (mooring, thruster)	Limiting environments for wire or fiber rope to remain clear of seabed	Permitted	Informative	Permitted	Informative
(B) Clearance, Mooring Line with Sea Surface		RRP	Comment	RRP	Comment
Intact system (mooring, thruster)	Fiber rope minimum depth below sea surface at pretension	Recommended	—	Permitted	Informative
(C) Clearance, Mooring Line with Hull					
Intact system (mooring, thruster), external turret, taut lines	Mooring line remains clear of the hull	Required	Avoid chaffing	—	—
Intact system (mooring, thruster), slack lines	Mooring line remains clear of the vessel's hull in environments up to the design return period (see Tables 1 and 2)	Required	Avoid rare contact	Permitted	Avoid rare contact
Single failure (mooring, thruster), slack lines	Mooring line remains clear of the vessel's hull in environments up to the design return period (see Tables 1 and 2)	Recommended	Avoid rare contact	Permitted	Avoid rare contact
Double failure (mooring, thruster), slack lines	Limiting environments for mooring line to remain clear of vessel hull	Permitted	Informative	Permitted	Informative
(D) Clearance, Mooring Line with Risers, Mooring Lines, Pipelines, Seabed Assets, Exclusion Zones		RRP	Comment	RRP	Comment
Intact system (mooring, thruster)	Mooring line remains clear in environments up to the design return period (see Tables 1 and 2)	Required	—	Required	—
Single failure (mooring, thruster)	Mooring line remains clear in environments up to the design return period (see Tables 1 and 2)	Recommended	Risk assessment	Recommended	Risk assessment
Double failure (mooring, thruster)	Limiting environments for mooring line to remain clear	Permitted	Informative	Permitted	Informative
(E) Clearance, Surface, and Subsurface Buoys		RRP	Comment	RRP	Comment
Intact system (mooring, thruster)	Maximum submergence of surface buoys and maximum depth of subsurface buoys in environments up to intact design return period (see Tables 1 and 2)	Required	—	Required	—
Single failure (mooring, thruster)	Maximum submergence of surface buoys and maximum depth of subsurface buoys in environments up to one failure design return period (see Tables 1 and 2)	Required	—	Required	—
Double failure (mooring, thruster)	Limiting environments for submergence of surface buoys and maximum depth of subsurface buoys	Permitted	Informative	Permitted	Informative
(F) Clearance, Trench with Anchor		RRP	Comment	RRP	Comment
Intact system (mooring, thruster)	Trench (due to mooring line motions at touchdown) far from anchor so that AHC is not affected	Permitted	Special case as needed	Permitted	Special case as needed
(G) Clearance, Anchor with Mooring Line, Pipeline, Seabed Assets, Exclusion Zones		RRP	Comment	RRP	Comment
All (intact, one and two failures)	Anchors with AHC < mooring line strength and in the drag path	Required	300 m	Required	300 m
All (intact, one and two failures)	Anchors with AHC < mooring line strength and NOT in the drag path	Required	100 m	Required	100 m
All (intact, one and two failures)	Anchors with AHC > mooring line strength	Required	100 m	Required	100 m

NOTE The colors are only intended to make it easier to the user to identify the respective parts of the table.

6.2.5 Fatigue Analysis Cases

For permanent systems, the total fatigue damage caused by low- and wave-frequency motions of the installed system and where applicable by VIMs of the floating platform shall be calculated. The fatigue life of all the components of the mooring system (line segments, connectors, anchors, on-vessel line foundations) shall be evaluated. Analysis cases for assessing fatigue damage of permanent systems are listed in Table 5; acceptance criteria and methods for calculating fatigue damage are in Sections 7 and 8, respectively. For driven anchor piles, the dynamic loads due to hammer impact during pile installation shall be calculated and added to the in-place fatigue damage resulting from the dynamic mooring line tensions at the anchor.

Stationkeeping analyses shall be performed for the intact system and for the range of vessel drafts and pretensions applicable to the permanent system. A permanent system may be configured with different numbers of risers, umbilicals, and offloading lines during different phases of its life resulting in different pretensions, dynamic responses, and rates of fatigue damage accumulation for each configuration. The fatigue analysis shall account for the various system configurations and the historic or expected number of years for each system configuration.

The environmental load cases used in the fatigue analysis, the fatigue weather bins shall be based on site-specific long-term distribution of winds, wind-waves, currents, and swell-waves. It is recommended that the multiyear hindcast of daily (normal) wind, wave, and current conditions, and their global directions, be used directly in the stationkeeping fatigue analysis. Alternatively, a set of fatigue weather bins may be developed from the site-specific multiyear hindcast that is statistically representative of the long-term distribution of wind, wave, and current conditions and their simultaneous global directions. For some turret moored systems, thrusters are used to control the vessel's heading in daily or normal environmental conditions; for these systems, the effect of the thruster's heading control on the vessel relative environmental directions and total fatigue damage should be included in the fatigue analysis.

For moored systems that are subject to VIM fatigue damage due to the long-term distribution of current conditions shall be added to the fatigue damage resulting from wind and wave conditions. Additionally, the fatigue damage due to the worst single VIM event with a return period of 100 years or less (an annual probability of occurrence of 10^{-2} or greater) shall also be calculated.

Table 5—Fatigue Analysis Cases: Permanent Systems

Fatigue Analysis Cases	Fatigue Damage Due to	RRP
Intact system (mooring, thruster)	Site-specific fatigue weather bins or direct use of hindcast	Required
Intact system (mooring, thruster), single event	Single-event extreme VIM response, e.g. spar and semi-VIM	Required
Installation, single event	Pile driving	Required

For long-duration (more than a couple of months) MOU operations in fatigue-driven environment or mooring design, a fatigue analysis may be conducted to assess the fatigue performance of the mooring system; particular attention should be given to Kenter links and other components (e.g. repeatedly deployed mooring hardware) with limited fatigue resistance. When assessing the fatigue performance of MOU mooring, the fatigue damage from previous deployments should also be accounted for.

6.3 Installation Considerations at Design Stage

6.3.1 Weather Windows for Installation

The mooring system design and the installation procedures should minimize the time required to install the mooring system. The storm-safe condition is defined as the minimum number of mooring lines that are

required to be connected before the floating structure can survive the site-specific seasonal *storm* (e.g. storm, loop, or eddy current, etc.) determined by a risk assessment. The risk assessment should consider the consequences of failure (e.g. nearby facilities, safety of people, etc.).

Where the consequence of failure is entirely financial, the owner or the operator shall select the return period of the storm, the time required to achieve the storm-safe condition, and the safety factor. However, to ensure no damage to mooring components, the maximum tension should not exceed 60 % of the component's break strength.

Where the consequence of failure is not purely financial (e.g. impact on safety and/or the environment), (1) the storm shall not be less severe than a 1-year return period site and seasonal specific storm (API 2MOP), (2) the time required to achieve the storm-safe condition shall be specified by the owner or the operator, and (3) to ensure no damage to the mooring components, the maximum tension should not exceed 60 % of the component's break strength.

In addition to maximum line tension, other mooring system constraints may apply (e.g. mooring lines crossing over risers, pipelines, or other infrastructure, polyester or wire rope touching the seabed, etc.) and should be assessed in the stationkeeping analysis and included in the risk assessment.

6.3.2 As-installed Mooring System and Design Criteria

The owner or the operator shall verify that the as-installed mooring system satisfies all design criteria in Section 7 for the conditions specified in 6.2. If the as-installed mooring system does not meet the design criteria, appropriate plans shall be developed and implemented in a timely fashion to ensure that the design requirements are satisfied.

Installation tolerances (for anchors, installed line segment properties, twist in line segments, pretensions, etc.), procedures, and acceptance criteria shall be developed by the owner or the operator to ensure that the installed mooring system satisfies the assumptions made in the design or site assessment. In particular, mooring line pretensions used in the strength and fatigue analysis shall be consistent with the installed pretension; this is especially important for mooring systems with grouped lines. If perfect load sharing between lines within a group is used for the strength and fatigue analysis, the installation procedures and acceptance criteria shall ensure that the installed mooring system also has perfect load sharing. However, if the mooring system strength and fatigue analyses uses a tolerance on line pretensions, the installation procedures and acceptance criteria shall also result in pretensions within that variation; for example, with a ± 10 % variation in pretensions, the installation procedures and acceptance criteria shall also result in pretensions within a ± 10 % variation.

6.4 Corrosion, Wear, and Abrasion Allowance for Chain

Protection against corrosion, abrasion, and interlink wear shall be provided for permanent mooring systems. Because of the lack of proven theoretical models for predicting corrosion, abrasion, and wear rates, the allowances used in design should be based on historical data. Where historical data for moored systems nearby or in the general region of the facility exist, they should be referenced when developing corrosion, abrasion, and wear rates for the permanent mooring system.

It is realized that corrosion, abrasion, and wear originate from different sources. In the absence of separate corrosion, abrasion, and wear data, their design allowances are typically combined into one allowance.

For chains, a corrosion, abrasion, and wear allowance shall be included in the design by an appropriate increase in the link diameter. The increase should be determined by a site-specific assessment dependent upon many parameters; for example, these could include the following:

- coatings or other forms of protection;
- the locations of the links (in the splash zone, submerged catenary, or touchdown zone);

- level of dissolved nitrogen;
- level of dissolved oxygen;
- water temperature;
- water salinity;
- microbiological flora and fauna;
- frequency of cleaning;
- characteristics of mooring line motions (at the top of the line, below buoys, or at the touchdown point); and/or
- soil conditions.

If site-specific corrosion, abrasion, and wear data are not available, the range of allowances given in A.6.4 may be considered in the design.

6.5 Sheathed and Unsheathed Wire Rope

For permanent moorings, sheathed wire ropes are generally used for wire segments in the water column, whereas unsheathed wire ropes have been successfully deployed for ground segments that are always in contact with the seabed. Corrosion of wire rope at connections to sockets can be accelerated by the galvanized wire acting as an anode for adjacent components. For permanent systems, the socket should be electrically isolated from the adjacent component. Additional corrosion protection can be achieved using sacrificial anodes to this area.

7 Design and Site Assessment Criteria

7.1 Safety Factors for Mooring Component Strength

7.1.1 Line Tensions

For mooring line components, acceptable tension limits are defined with respect to the component's end-of-life break strength (ELBS). Mooring analyses may be performed in the frequency or time domain. The calculation of line tensions due to wave-frequency vessel motions shall include the dynamic effects of the line's velocity (drag forces) and acceleration (inertial forces); in Table 6, this is referred to as dynamic analysis. The ELBS shall allow for the reduction in strength by reducing the diameter to account for corrosion, abrasion, and interlink wear. For mobile moorings that satisfy the requirements of API 2I, the ELBS may be taken as equal to the CBS corrected for corrosion and complex loading condition (e.g. bending-tension combination).

Where mooring components are subject to more complex loading, in sheaves, fairleads, bending shoes, out-of-plane loading at pile and turret padeyes, etc., the strength of the component is likely to be less than the strength in tension loading only. The strength of the component (ELBS) in complex loading to be used in calculating the strength factor of safety shall be determined through finite element analysis (FEA) or other reliable sources (such as testing or prior project experience).

Tension limits for intact and damaged conditions of permanent and mobile stationkeeping systems in normal and extreme environmental conditions shall be in accordance with Table 6.

Table 6—Safety Factors for Tensile Strength of Mooring Line Components

System Condition	Safety Factor: End-of-life Break Strength/Max Tension, with Dynamic Analysis	
	Permanent Mooring	Mobile Mooring
Intact (mooring, thrusters)	1.67 (60 % of ELBS)	1.67 (60 % of ELBS)
Single failure (mooring, thrusters)	1.25 (80 % of ELBS)	1.25 (80 % of ELBS)

Safety factors for double failures (lines or thrusters) and thruster blackout cases and the associated environmental return period or AJP may be defined by the owner or the operator. The calculation of the annual joint probability of simultaneous occurrence of a thruster blackout and an environmental condition of a particular return period is described in A.6.2. Analysis cases, system conditions, and environmental return periods are specified in 6.2.2.1 and 6.2.2.2.

The criteria in Table 6 applies to all mooring line components (e.g. chain, wire rope, fiber rope, H-links, shackles, Kenters, etc.) and applies to both passive and active stationkeeping systems (i.e. passive, TAMs, and disconnectable moorings).

Where mooring lines contain fiber rope segments, tensions are sensitive to the load-elongation properties of the fiber rope segments. The nonlinear elastic properties of the fiber rope shall be modelled based on test data for the rope. Differences in fiber rope segment lengths due to permanent elongation can result in unequal load sharing for lines within a group and thus have an impact on extreme tensions in both intact and one-line damaged conditions.

Strength analyses based on idealized mooring system properties can result in a significant underestimation of the extreme tensions. It is important to conduct sensitivity checks and allow for the uncertainty in outboard segment lengths, pretensions, load sharing, and stiffness in the strength analysis.

For TAM systems, single failures include mooring line failure and the single worst failure (SWF) of the ITCS as identified by the failure modes and effects analysis (FMEA), the ITCS consists of the thrusters, and the control, power generation, and distribution systems. For TAM systems, definitions of intact and damaged conditions are given in Table 7.

Table 7—Definitions of Intact and Damaged Conditions for Thruster-assisted Mooring

Definitions of System Conditions		Mooring	Thruster
Intact		Intact	Intact
Damaged—Single failure	Case A	One-line failed	Intact
	Case B	Intact	Single worst failure
Damaged—Double failure	Case C	Two-lines failed	Intact
	Case D	One-line failed	Single worst failure

7.1.2 Anchor Factors of Safety

7.1.2.1 General

Safety factors for conventional drag embedded anchors, plate anchors, gravity anchors, suction piles, and driven piles are specified herein. Other anchor types (e.g. gravity embedded anchors, scoop anchors, etc.) may be used provided they can be documented to achieve similar levels of reliability to the anchors discussed below.

For plate and gravity embedded anchors, where it has been demonstrated by field tests or other methods that the overloading behavior (failure mode) is similar to conventional drag anchors, drag anchor factors of safety may be used.

The AHC should be based on site-specific soil properties.

7.1.2.2 Drag Embedded Anchors

The AHC of a drag anchor is the horizontal component of the steady pull that can be resisted by the anchor at continuous drag. This includes the soil resistance on the buried portion of the chain or of the wire rope but excludes the friction of the chain or wire rope lying on the sea floor.

Safety factors that shall be used for drag anchors used in permanent and mobile stationkeeping systems are specified in Table 8. Safety factors for vertically loaded plate anchors are given in 7.1.2.3.

Table 8—Safety Factors for Drag Anchor

System Condition	Safety Factor: AHC/Max Load, with Dynamic Analysis		
	Permanent Mooring	Mobile Mooring ^a	
		In Close Proximity or with Riser Connected or Anchors in Drag Path	Away from Other Structures without Riser Connected and Anchors Not in Drag Path
Intact (mooring and thrusters)	1.5	1.0	0.8 ^b
Single failure (mooring, thrusters)	1.0	OD	OD
^a OD is operator defined. ^b According to the information between Table 8 and Table 9 for allowing safety factor of 0.8 for mobile mooring anchors, this design approach is based on U.S. Gulf of Mexico experience in clay seabed condition; in other soil conditions, operators shall make the safety factor decision for mobile anchor design based on their own experience.			

For MOU moorings in the survival condition, anchor slippage can result in redistribution of mooring line loads with the most loaded line shedding load to adjacent lines, therefore, increasing the chance of surviving a storm event. However, for close proximity MOU mooring or MODUs in the operating condition, with the drilling riser connected or where subsea infrastructure lies in the drag path of the anchor (e.g. pipeline), anchor movement should be avoided (i.e. the safety factor for MOU drag anchors depends on the consequence associated with anchor movement). In addition, see 6.2.2, 6.2.3, and 6.2.4.

Drag embedded anchors should not be loaded vertically (uplift) in normal operating conditions. This requirement is especially important for anchors in sand and hard soil where anchor penetration is shallow. Vertical loads may be acceptable in survival conditions for certain types of high-efficiency anchors in clay soils with deep penetration for which sufficient research has been conducted and field experience gained to confirm that they can withstand vertical loading.

The following conditions shall apply to vertically loaded high-efficiency drag embedded anchors.

- a) Vertical loads are allowed only in extreme (survival) conditions.
- b) It should be confirmed that the soil conditions and the anchor test load will result in deep penetration (soft clay). No vertical loads should be applied if the soil conditions are not thoroughly investigated or the anchor test load is insufficient to achieve deep penetration.
- c) The maximum line angle at the mudline (including the effects of low-frequency vessel motions) in extreme (survival) conditions is less than 20 degrees for both the intact and damaged condition. The AHC shall be reduced by the factors specified in Table 9 based on the calculated maximum line angle at the mudline.

Table 9—AHC Reduction Factors for Vertically Loaded High-efficiency Drag Anchors in Soft Clay with Deep Penetration

Mudline Angle (degrees)	AHC Reduction Factor
0	1.00
5	0.98
10	0.95
15	0.89
20	0.81

The line angle at the mudline should be zero at the early stage of test loading to ensure anchor penetration. When evaluating if vertical loading of a drag anchor is acceptable, the estimated vertical load at the mudline “dip down point” should be calculated and compared to the anchor weight. Vertical loads less than the anchor weight are less likely to unseat the anchor.

7.1.2.3 Vertically Loaded Plate Anchors

Acceptance criteria that shall be used for vertically loaded plate anchors [see Annex A for an example of vertically loaded anchors (VLAs)] used in permanent and mobile systems are given in Table 10. The safety factor is defined as the AHC divided by the maximum anchor load from a dynamic analysis, where the AHC is for the direction in which the anchor is loaded, i.e. the direction of loading in the failure envelope.

Table 10—Safety Factors for Vertically Loaded Plate Anchors

System Condition	Safety Factor: AHC/Max Load, with Dynamic Analysis	
	Permanent Mooring	Mobile Mooring
Intact (mooring, thrusters)	2.0	1.5
Single failure (mooring, thrusters)	1.5	1.2

7.1.2.4 Anchor Piles and Gravity Anchors

The vertical and horizontal resistances of anchor piles (gravity, suction, driven, or dynamically embedded) and gravity anchors shall be determined in accordance with ISO 19901-4. The maximum vertical and horizontal components of the extreme mooring line tensions derived from dynamic analysis shall not exceed the vertical and horizontal resistances divided by the safety factors provided in Table 11.

Table 11—Safety Factors for Pile Anchors and Gravity Anchors

System Condition	Safety Factor: AHC/Max Load, with Dynamic Analysis			
	Permanent Mooring		Mobile Mooring	
	Vertical	Horizontal	Vertical	Horizontal
Intact (mooring, thrusters)	2.0	1.6	1.5	1.2
Single failure (mooring, thrusters)	1.5	1.2	1.2	1.0

7.2 Vessel Position, Offsets, and Heading

7.2.1 Position Limits

Vessel offset, and heading (if applicable), limits for permanent and mobile systems shall be established by the owner or the operator.

Offset and heading limits should be based on the requirements of equipment, such as drilling or production risers, umbilicals, gangways, etc., as well as the requirement for safe disconnection of disconnectable systems. Generally, different criteria will apply to operating, standby, and survival conditions and for intact, damaged, and transient cases. For example, MODU offset limits for the riser connected drilling (rotating), riser connected nondrilling (nonrotating), and survival (riser disconnected) cases are usually different, and these should be based on the riser and wellhead mechanical limits. For MOU operations, such as diving support, construction, pipe-laying, etc., offset criteria for operating, standby, and survival conditions shall be specified by the owner or the operator.

7.2.2 Position Monitoring

Permanent and mobile vessels shall be equipped with an offset monitoring system. If the vessel's heading is important for operations or the heading is to be controlled (e.g. thruster-assisted turret moored vessels), the vessel shall be equipped with a heading monitoring system.

The redundancy and accuracy requirements of the position monitoring system(s) shall be defined by the owner or the operator.

7.3 Requirements for Clearances

7.3.1 General

Clearances between the vessel, its mooring lines and anchors with other surface, subsurface, or seabed structures shall be calculated for the analysis cases specified in 6.2.4 and shall satisfy the requirements herein. Clearance checks should include design installation tolerances of the mooring system.

7.3.2 Mooring Line with Seabed (Thrash Zone)

Fiber or steel wire ropes and their terminations can become damaged by repeated contact with the seabed; consequently, it is recommended that chain be used at the touchdown, or thrash zone, of the mooring line. Wire ropes may be in contact with the seabed provided the contact remains throughout the full range of predicted line tensions.

The clearance requirements that shall be followed between wire or fiber ropes and the seabed in Table 12 apply to the bottom end of wire or fiber rope segments that are in the water column, i.e. to prevent wire or fiber rope of the slack lines repeatedly contacting the seabed (wire or fiber rope in the thrash zone).

Table 12—Minimum Clearances between Bottom of Suspended Wire or Fiber Rope and Seabed

Clearance, Rope with Seabed	Permanent Mooring ^a		Mobile Mooring ^a	
	RRP	Minimum Distance	RRP	Minimum Distance
(A) Steel Wire Rope				
Intact (mooring, thrusters)	Recommended	> 1 m	Permitted	OD
Single failure (mooring, thrusters)	Permitted	OD	Permitted	OD
(B) Fiber Rope				
Intact (mooring, thrusters)	Required	> 1 m	Recommended	> 1 m
Single failure (mooring, thrusters)	Recommended	> 1 m	Permitted	OD
^a OD is operator defined.				

The susceptibility to damage of a fiber rope due to seafloor contact depends on the fiber rope's jacket, design of the filter barrier, the seafloor characteristics, and the line's motions at the touchdown point. In addition, because fiber ropes are close to neutrally buoyant, or slightly negatively buoyant, they are susceptible to movement and possible damage on the seafloor. Requirements for rope construction, seabed survey, and soil conditions are specified in API 2SM for fiber ropes that are in contact with the seabed.

7.3.3 Mooring Line with Sea Surface

For fiber moorings, a suitable length of steel wire or chain should be provided at the top end of the fiber rope mooring leg. The upper steel segment can be used for adjustments of the mooring leg's tension to compensate for rope elongation over the life of the mooring, and for repositioning operations. Therefore, suitable equipment for adjusting the length of the upper steel mooring component segment should be provided for each mooring leg. For more information, see API 2SM.

For permanent systems, it is recommended that the owner/operator establish clearance requirements between the top of the fiber rope and the sea surface. In the absence of owner/operator defined clearance requirements for permanent systems, a minimum clearance of 100 m for the intact mooring system under design pretension is recommended according to Table 13 and Table 4.

Table 13—Minimum Clearance between Top of the Fiber Rope and Sea Surface

Clearance, Fiber Rope with Sea Surface	Permanent Mooring ^a		Mobile Mooring ^a	
	RRP	Minimum Distance	RRP	Minimum Distance
Intact (mooring and thrusters) under design pretensions	Recommended	OD	Permitted	OD
^a OD is operator defined.				

7.3.4 Mooring Line with Hull

For external turret moored vessels, clearances between the mooring lines and vessel are usually smallest in normal operating conditions; when the vessel's orientation places it over a line or group of lines, clearances generally increase with the severity of the environment. For other types of permanent and mobile moorings, clearances between the mooring line and hull, or anchor bolster, are generally at minimum for slack lines in extreme environmental conditions.

For permanent mooring systems, the owner or the operator shall define the minimum allowable clearances for the intact cases defined in part (C) of Table 4. For permanent systems with a single failure (line or thruster), the owner or the operator should also define the minimum allowable clearance for the slack lines.

For MOUs, the clearance requirements and associated vessel drafts, pretensions, and environmental conditions should be established by the owner or the operator for the cases in part (C) of Table 4.

For permanent or mobile systems with two failures (lines or thrusters), analyses may be performed to determine the limiting environmental conditions for which the mooring lines remain clear of the hull.

7.3.5 Mooring Line with Risers, Mooring Line, Pipeline, Seabed Assets, and Exclusion Zones

Mooring lines shall remain clear of risers, the mooring lines of other installations, pipelines, seabed infrastructure, and exclusion zones [part (D) of Table 4] in the conditions specified in 6.2.2. A minimum clearance of 10 m under the intact condition shall be maintained. The clearance requirement of 10 m does not apply to mooring lines and risers close to or at the vessel (e.g. for a turret moored vessel, the clearances between lines and risers at or near to the turret may be less than 10 m).

Where a mooring line within the elevated part of its catenary crosses a pipeline on the sea floor, a minimum clearance of 10 m under the intact condition shall be maintained. A mooring line may pass over and be in contact with a protected pipeline, provided this contact remains throughout the full range of predicted intact line tensions (i.e. the contact does not change causing abrasion or damage to the pipeline or the mooring line).

It is recommended that mooring lines remain clear of other mooring lines, pipelines, seabed infrastructure, and exclusion zones in the single-failure conditions specified in 6.2.2. Surface or subsurface buoys and fiber rope line segments may be used to maintain clearances between a failed mooring line and other mooring lines, pipelines, seabed infrastructure, and exclusion zones. A minimum clearance for the single-failure condition shall be specified by the owner or the operator.

7.3.6 Buoys, Surface, and Submerged Buoys

7.3.6.1 General

Surface and subsurface buoys may be used in intact and damaged cases to manage clearances, where a mooring line crosses over a pipeline or another installation's mooring line or to maintain clearance with anchor bolsters. Analyses shall be performed to calculate the maximum submergence of a surface buoy or maximum depth below the water surface of a subsurface buoy as specified in part (E) of Table 4.

The motions of buoys deployed near or on the water surface can cause excessive wear to connecting links resulting in component failure; as a result, buoy motions shall be accounted for in the design of the components connecting the buoy to the mooring line.

Subsurface buoys can be used to minimize the wave motions of the buoy and the resulting wear and fatigue damage on the hardware connecting the buoy to the mooring line. By placing the buoy away from the surface, the risk of the buoy being damaged from a collision with a surface vessel is also eliminated.

Both above risks have been observed in the field. However, submerged buoys are generally more of an investment than surface buoys and usually require a remotely operated vehicle to retrieve them if connection to the buoy or mooring line is needed. The deployment scheme of the submersible buoy with its mooring line attached should be considered at the design stage to ensure that the buoy assembly will not be submerged beyond its rated water depth. If the buoy is not an in-line component, the hardware required to prevent entanglement of the pennant line around the mooring line, due to torque responses of the system during installation and while in service, should be part of the buoy's design.

Buoys should be filled with foam or incorporate measures, such as compartmentalization, to minimize the risk of sinking in the event of damage. Surface and subsurface buoys should be designed for the maximum buoy submergence depth for the analysis cases in Table 4. The maximum safe working depth for mid-line buoys should be based on analyses and/or testing using applicable design and manufacturing codes.

7.3.6.2 Surface Buoys

Surface buoys shall be designed to remain at the surface (i.e. a maximum 67 % submergence) in all intact and single-failure conditions, unless specifically designed for submergence (see 7.3.6.3).

7.3.6.3 Subsurface Buoys

Subsurface buoys of steel construction, designed for external pressure, shall be designed in accordance with an appropriate recognized pressure containment standard for use at the maximum operational depth identified by the mooring analysis. The design safety factor shall be no less than 1.5 for permanent moorings and 1.2 for mobile moorings. ASME *Boiler and Pressure Vessel Code*, Division 1, Section VIII provides detailed engineering requirement for subsurface buoys of steel construction designed for external pressure.

For foam-type buoys, an allowable hydrostatic pressure shall be determined by dividing the hydrostatic collapse pressure by a design safety factor, where the choice of the design safety factor depends on the design service life and criticality of the buoy. The long-term water absorption rate of the foam material at its service depth shall be determined and included in the design stage of the mooring system.

7.3.6.4 Submerged Turret Buoy

Submerged turret buoys are typically used on FPSOs with an internal disconnectable turret. The net buoyancy of the buoy should be adequate to support the risers, umbilicals, and mooring lines before, during, and after disconnection. The mooring line pretensions and buoyancy should be designed so that upon release of the buoy, the inertial motion does not result in the buoy falling to the seafloor, with the risers and mooring lines. The intent of the design is that the mooring and riser connection point remains a few hundred feet below the waterline to avoid the bulk of the environmental surface wave and current forces. In the connected mode, the turret buoy should also allow free rotation of the vessel in all loading conditions.

7.3.7 Effect of Mooring Line Trenching on Anchors

To prevent trenches from degrading the holding capacity of the anchor, the owner or the operator may define a minimum allowable distance between the anchor and the mooring line's touchdown point in *representative* return period environmental conditions. Alternatively, the anchor may be designed (sized) so that the AHC, with the (predicted) end of field life trench at the anchor is sufficient to satisfy anchor factors of safety.

Guidance for analyzing where the distance between the trench and the anchor is sufficient to ensure that the AHC is not reduced is specified in part (F) of Table 4 and described in A.8.6.4.

7.3.8 Anchor with Mooring Line, Pipeline, Seabed Assets, and Exclusion Zones

7.3.8.1 Clearance between a Drag Anchor and Other Installations

If the drag path of a drag anchor is expected to bring it close to another installation, the final anchor position shall allow a margin of at least 300 m of drag distance before contact can occur with the installation. If the anchor's drag direction will not result in contact with the installation, the final anchor position shall be at least 100 m from the installation.

7.3.8.2 Clearance between Other Types of Anchors

Other types of anchors may also have clearance requirements that are unique to their holding capacities and installation method. It is important to understand how the anchor achieves its holding capacity and consider common failure mechanisms to adequately account for the needed clearance between other types of anchors.

7.4 Safety Factors for Mooring Component Fatigue Resistance

The fatigue endurance of chain, Kenter and Baldt links, and steel wire rope shall be verified with the T-N curves provided in Table 14, using a minimum fatigue factor of safety of 3. Mooring components are considered uninspectable, and this fatigue safety factor of 3 applies to uninspectable components. The fatigue endurance of well-constructed polyester and high-modulus polyethylene (HMPE) rope, for tension ranges (T) of less than 50 % of CBS, is at least six times that of spiral strand wire rope with a mean load ratio (Q) of 0.3, according to API 2SM, API 2FC-2, and ISO 19901-7:2013.

For anchor structural fatigue design factor of safety, the requirement in the *fatigue life safety factors* table of API 2A-WSD shall be satisfied.

For moored systems that are subject to VIM, fatigue damage due to the long-term distribution of current conditions shall be added to the fatigue damage resulting from wind and wave conditions. In addition, fatigue damage due to the worst single VIM event with a return period of 100 years or less (an annual probability of occurrence of 10^{-2} or greater) shall be calculated; the required fatigue safety factor for this event alone is 3.0.

For driven anchor piles, the dynamic loads due to hammer impact during pile installation shall be calculated and added to the in-place fatigue damage resulting from the dynamic mooring line tensions at the anchor.

The T-N fatigue curves used to calculate fatigue lives of mooring components are given by Equation (1).

$$N = \frac{K}{R^m} \quad (1)$$

where

N is number of cycles;

R is ratio of tension range (double amplitude) to RBS. For chain, RBS is taken as CBS of oil rig quality (ORQ) common chain link of the same size for common or connecting links. Guidance on increase of chain diameter for corrosion, wear, and abrasion is contained in 6.4. For wire rope, RBS is the same as CBS.

Values of m and K for common mooring line components are provided in Table 14.

Table 14—T-N Fatigue Curve Parameters, m and K , for Use with a Fatigue Safety Factor of 3.0

Component	m	K
Common studlink	3.00	$1000 = 10^3$
Common studless link	3.00	$316 = 10^{2.5}$
Kenter connecting link (for example)	3.00	$178 = 10^{2.25}$
Six/multistrand wire rope (corrosion protected)	4.09	$10^{(3.20 - 2.79 Q)}$, $K = 231$, when $Q = 0.3$
Spiral strand wire rope (corrosion protected)	5.05	$10^{(3.25 - 3.43 Q)}$, $K = 166$, when $Q = 0.3$
Polyester or HMPE rope [six times spiral strand, tension range (R) less than 50 % CBS]	5.05	$1000 = 10^3$
NOTE Q is the ratio of mean tension to CBS of the wire rope.		

The RBS for common chain or connecting links of all grades is equal to the CBS of ORQ common chain link of the same diameter. CBS for ORQ grade chain in kN = $0.0211 \times d^2 \times (44 - 0.08d)$, where d is the nominal bar diameter in mm.

NOTE See A.7.4 for additional guidance on use of the above T-N curves.

The T-N curves in Table 14 are based on pure tension-tension loading (i.e. tension loading without bending or torsion). The fatigue life of mooring components (chain, wire rope, connectors, etc.) that are subject to loading that is not pure tension [e.g. chain in the fairlead, on bending shoes, in the thrash zone, at articulations and terminations, out-of-plane bending (OPB), etc.] should be determined using other methods. For those chain links that are subjected to more complex loading, the fatigue damage assessment methodology shall be approved by the owner.

Where mooring lines contain fiber rope segments, the calculated fatigue life of the steel components of the mooring line is sensitive to the load-elongation properties of the fiber rope segments. The nonlinear elastic properties of the fiber rope shall be modelled based on test data for the rope. Differences in fiber rope segment lengths due to permanent elongation can result in unequal load sharing for lines within a group and thus have an impact on mean tensions and tension ranges in the fiber and steel segments.

Fatigue analyses based on idealized mooring system properties can result in a significant underestimation of the fatigue damage. It is important to conduct sensitivity checks and allow for the uncertainty in the lengths of outboard segments, load sharing, mean load, and stiffness in the fatigue analysis (see A.7.4).

To account for the effects of corrosion and wear over the design life, when determining the RBS of common chain or connecting links, the diameter should be taken equal to the nominal diameter minus half of the corrosion and wear allowance. That is, the mid-life or average diameter of chain links and connectors should be used when calculating fatigue damage.

For complex loading (e.g. tension, bending, and or torsion) or for nonstandard mooring line components, where fatigue test data does not exist (e.g. shackles, H-links, tri-plate, and specialty connectors), fatigue resistance shall be demonstrated through the use of S-N curves for the base material with hot spot stresses or stress concentration factor (SCF) derived from FEA. For complex loading or nonstandard components, the S-N curves and associated fatigue safety factors shall be specified by the owner or the operator.

The T-N curves in Table 14 should be used in conjunction with a minimum fatigue safety factor of 3 and are associated with a probability of fatigue failure of about 10^{-4} in 10,000 links; see derivation of fatigue curves contained in API 2FC-1.

The owner may approve the use of alternative fatigue curves with an associated fatigue safety factor. The derivation of an associated fatigue safety factor for these alternative fatigue curves should follow the methodology in API 2FC-1 and target the same overall reliability of a probability of fatigue failure of about 10^{-4} in 10,000 links. The chain diameter calculated using the alternative fatigue curve and associated safety factor shall not be smaller than the diameter calculated with the fatigue curve and associated safety factor from this standard.

The T-N curves for wire rope are for wire ropes protected from corrosion. Elements for corrosion protection include galvanizing, sheathing, blocking compound, and zinc filler wires. Careful investigation considering the design life, inspection, and change-out strategy should be carried out to determine the combination of these elements needed for a specific project. Mean load has a significant influence on wire rope fatigue life and therefore should be included in the design curve equations. A mean load of 0.3 RBS is considered to be representative for conventional mooring systems.

8 Analysis

8.1 General

Mooring analysis shall be performed to calculate system responses for the design conditions provided in 6.2 and 6.3. The calculated system responses shall be compared to the acceptance criteria provided in Section 7.

The mooring designer shall confirm that output of the analysis can be used to verify that all components meet their individual design requirements such as strength, fatigue, compression, contact, curvature, torsion, etc.

The mooring analysis shall:

- a) Cover configurations based on the anticipated installation sequence and planned future installations of:
 - 1) risers;
 - 2) topsides equipment.
- b) Account for variation in the following:
 - 1) pretension due to change in vessel draft and trim or payout of lines;
 - 2) vessel properties (virtual mass and inertia, damping coefficients, projected areas, etc.);
 - 3) wind, wave, and current force coefficients;
 - 4) wave motion RAOs due to changes in draft and trim;
 - 5) sea floor slope.
- c) Include sensitivity analysis to define installation tolerances to ensure that the installed mooring system satisfies the assumptions made in the design or site assessment (also see 7.3.2).
- d) Take into account the effect of risers on system responses (stiffness, damping, mean load). The influence of the risers on the mooring system response may be ignored if doing so results in a more conservative mooring design.

For permanent systems not subject to any regular marine growth removal, marine growth on the hull, risers, and mooring system shall be accounted for in the mooring analysis. Properly accounting for the effect of marine growth on mooring and risers requires a coupled analysis. The more conservative case (i.e. either with or without marine growth) shall be identified and used in the mooring analysis.

The physical properties of the mooring line components, weight, stiffness, diameter, etc. that are used in the mooring analyses shall be the nominal values (i.e. catalogue values with no deduction for corrosion, abrasion, or wear).

In the case of fiber rope, load-elongation properties used in the mooring analysis shall be defined based on the mooring system behavior and appropriate test data. A comprehensive discussion on testing and modeling fiber mooring ropes for mooring analysis purposes is provided in API 2SM.

It should be understood that, in this section, “risers” includes a single (drilling) riser, multiple risers, and umbilicals.

Recommendations for determining the properties and modeling fiber mooring ropes in the mooring analysis can be found in API 2SM.

8.2 Analysis Methods

The methods generally used to compute the system responses of a moored floating structure are as follows:

- the frequency-domain approach,
- the time-domain approach, or
- a combination of frequency-domain and time-domain analysis.

These methods involve different degrees of approximation and are affected by different limitations and therefore do not necessarily yield consistent results. Both time-domain and frequency-domain analyses can include linear or nonlinear approximations. Furthermore, the effect of the vessel heading (mean and low-frequency variations) shall be taken into account when calculating the wave-frequency responses. This is particularly important for passive turret moored vessels and more so for transient, e.g. squall, events. If verification of the approach selected for the mooring analysis is required, an alternative approach, model test data, or full-scale measurements should be used.

A line-dynamic method of analysis shall be used where the analysis shall account for dynamic loads on the mooring lines and risers associated with mass, drag, and acceleration. Quasi-static methods where dynamic loads are neglected shall not be used for final design of permanent or final site-specific assessment of MOU moorings. When low-frequency damping is added as a user defined input, the amount of damping that is added shall be documented.

8.3 Coupling Effects

Interaction or coupling between the floating structure and the mooring and risers in the form of inertia, damping, mean load, and stiffness affects the responses of the floating structure. The impact of the coupling on the resulting system responses will vary depending on the size and type of floating structure, and the response mode being evaluated. The coupling between the floating structure and the mooring and risers can be captured to varying degrees. Both frequency domain and time domain can be coupled or decoupled, and line dynamics can be taken into account in both coupled and decoupled analysis. For decoupled analysis, the mooring designer should evaluate the impact of mooring line and riser damping, and riser stiffness if not included, in the system response. For CALM buoys without an offloading vessel connected, the effects of coupling are significant and should be included when calculating the buoy's wave-frequency motion response.

8.4 Environmental Loads on the Floating Structure

8.4.1 General

The floating structure offsets and motions to be used in the station keeping system design shall be evaluated for all relevant combinations of wind directions, wave directions, and current directions, consistent with the site-specific metocean characteristics. Both collinear and noncollinear combinations shall be assessed where site-specific information is lacking. Multiple wave trains with different directions (e.g. sea and swell) may be needed to properly describe the total wave environment at the site. The ability of the floating structure to change heading in response to changing environmental conditions may be taken into account.

For passive turret moored vessels in wind-squall events, where the wind speed increases over a short time period, the vessel heading before the squall arrives at the site (the initial heading) is determined by the nonsquall environmental conditions. For turret moored vessels in transient wind squall conditions, the directional distribution shall include all combinations of initial vessel headings and squall directions, consistent with the site-specific metocean conditions. Consequently, a load case shall consist of a vessel initial heading and a wind squall direction (wind direction at the time of maximum wind speed); then different squall time histories result in different realizations of system responses for each load case.

8.4.2 Wave Forces

Wave-induced forces (steady, low-frequency, and wave-frequency) shall be determined by analytical methods or empirically based on model testing with consideration of water depth effects. Approximate analytical methods include diffraction and radiation theory and slender member hydrodynamics.

The mean and slowly varying wave force components shall be accounted for in the analysis. In addition, vessel wave-frequency responses shall also be included, by input of wave displacement RAOs or wave force RAOs and hydrodynamic coefficients (mass, added mass, and damping).

Where the relationship between significant wave height (H_s) and peak period (T_p) is available, sufficient points along the H_s - T_p contour shall be evaluated to find the governing combination. The effect of current on wave forces shall be accounted for where relevant. This includes the change in intrinsic wave frequencies to apparent wave frequencies (encounter frequency effect), as well as changes in the magnitude of wave-induced forces.

For structures with slender members (semisubmersibles, spars), viscous wave drift forces should be considered as they may be larger than the diffraction-radiation forces.

The effect of water depth on the wave kinematics and forces shall be accounted for during design analysis of a floating platform mooring unless it is shown that the effect of water depth is not important for given vessel size and the range of wave period/length.

8.4.3 Wind Forces

Wind-induced forces shall be determined by wind tunnel tests, computational fluid dynamics (CFD), or numerical analysis methods.

NOTE See Annex A for more details.

The wind field contains energy near the natural frequency of a floating structure, which can produce a significant dynamic response. The wind dynamics (except for squalls) can be described by a steady component, based on the 1-hour average velocity plus a time varying component calculated from a suitable wind spectrum. The wind spectrum shall be defined over the full range of natural frequencies of the moored structure. The wind spectrum is used directly in frequency-domain analysis. In time-domain analysis, the wind spectrum is used to generate a number of different time histories (n-realizations), each depending on a different random seed.

Recommendations for wind profile, gust factors, and wind spectra can be found in API 2MET. For hurricane conditions, the ESDU wind spectrum is recommended; for non-hurricane conditions, the ISO [Norwegian Petroleum Directorate (NPD)] spectrum is recommended. For the ISO spectrum, there is a cutoff at 600 seconds. For systems with natural periods longer than 600 seconds, the recommended wind spectrum for non-hurricane conditions is the upper bound API spectrum ($\alpha = 0.01$).

NOTE See Annex A for a more detailed discussion.

For sites affected by wind squalls, the concept of a wind spectrum is not applicable. The analysis of corresponding wind-induced responses should be performed in time domain using time histories of both wind speed and direction that span the range of return periods required.

8.4.4 Current Forces and Vortex-induced Motion

Current force coefficients on large-body floating structures shall be determined by means of wind tunnel tests, towing tests, CFD, or numerical analysis tools. For coupled analysis, current loads shall be based on vessel-relative current velocities.

Floating structures consisting of large diameter cylindrical components or columns, such as spars and semisubmersibles, can experience low-frequency motions due to vortex shedding in the presence of currents. VIM and its effects shall be accounted for in the design of the mooring system for both the strength and fatigue limit states.

8.5 Loads on Mooring Lines and Risers—Wave and Current Forces

Direct wave loads on mooring lines and risers can typically be neglected for mooring system response.

The effect of current forces, loading, and damping on mooring lines and risers shall be determined. Current loading can be important for locations with high currents and systems in deepwater with many mooring

lines and risers. Mean current loads on mooring lines and risers shall always be included in the analysis. For coupled analysis, current loads shall be based on the slender body-relative current velocities.

8.6 Mooring Analysis for Strength, Offset, and Clearance

8.6.1 Basic Considerations

The mooring analysis shall be set up to produce the following outputs:

- a) line tension for each mooring component and at the end points of the mooring line;
- b) offsets of floating structure at all locations of interest;
- c) clearance between mooring components and the vessel, seabed, sea surface, field infrastructure, exclusion zones;
- d) extreme values of grounded mooring line length.

In some cases, mooring line tensions are adjusted for operational reasons and/or in advance of foreseeable survival environmental events. For the analysis of strength limit states, the modelling of the stationkeeping system and floating structure configuration shall reflect such adjustments. However, the adjustment of line tensions during a storm shall not be taken into account in the survival analysis.

If the results of the analysis indicate that a mooring line goes completely slack, the behavior should be further investigated.

The ELBS shall be used for calculating safety factors (see also 7.1.1). For used MODU mooring components, their ELBS is their MBS after inspection.

8.6.2 Extreme Value Statistics

The acceptance criteria shall be compared to the most probable maximum (MPM) or minimum value of the system response in the design event duration, consistent with the site-specific metocean conditions. Typically, the design event duration is taken as 3 hours of steady state conditions.

For time-domain analyses, characteristic extreme values of system responses may be determined by statistical fitting techniques. The analysis can consist of one long realization or multiple short realizations of the design environment. The total duration shall be long enough to obtain enough response cycles to reach statistical convergence of the predicted extreme responses. In time-domain analyses, care shall be taken to ensure that the input (wind, wave, and current) time histories are nonrepeating within a single realization or across multiple realizations.

For frequency-domain analysis, the extreme value distribution for each response shall be selected. Some frequency-domain programs by default assume a Rayleigh distribution; this is not necessarily correct for mooring system responses.

The offset location at which the extreme wave-frequency line tension is calculated shall be documented.

NOTE See A.8.6.2, where guidance for frequency-domain calculations and a simplified method for combining low-frequency and wave-frequency responses is provided; additional information on time-domain analysis is also provided.

8.6.3 Design Values for Responses to Transient Wind Squalls

The characteristic design value for line tension shall be taken as the mean or expected value of the peak mooring line tensions from all squall realizations within the governing load case. A load case here is a unique combination of initial vessel heading and squall direction (wind direction at time of peak wind speed).

The characteristic design value for vessel offsets is defined in two dimensions (Easting and Northing) and is therefore much more complex than the design value for line tension. Envelopes of vessel offset may be defined with varying levels of conservatism as follows:

- Option 1: Circular envelope based on maximum radial (R_{xy}) offset from each realization;
- Option 2: Contour based on maximum characteristic tension or utilization; or
- Option 3: Irregular shaped envelope containing all response trajectories.

8.6.4 Mitigating Mooring Line Trenching Effects on Anchor Holding Capacity

The owner or the operator shall assess the impact of trenching on the performance of the mooring system. An example of such an assessment is provided in Annex A.

8.7 Mooring Analysis for Fatigue

8.7.1 Basic Considerations

The fatigue weather bins (load-case matrix) shall be established that describes the long-term environment at the site. The fatigue weather bins can be constructed from the marginal distributions (e.g. sea and swell wave-scatter diagrams by direction, and wind and current speed and direction-scatter diagrams) each with an annual probability of occurrence or can be made up of a multiyear hindcast of wind, sea, current, and swell conditions. A mooring analysis is then performed for each weather bin and for a representative combination of vessel drafts and trims, and base case and future risers.

Components that are exposed to low-cycle/high-stress regimes (API 2FC-2) should be analyzed to assess damage accumulation during rare extreme events that may be of extended duration, such as a rise and fall of the 100-year event. The single 100-year return period event on its own shall not result in a fatigue failure; that is, the damage from the single 100-year return period event is evaluated separately from the long-term damage.

Depending on the mooring system configuration (catenary versus taut), the largest tension ranges are not necessarily found at the top of the mooring line.

The fatigue analysis shall be performed for the intact station keeping system and cover the range of vessel drafts and trims, and base case and future riser configurations. If the mooring system operates in different modes, for example, an FPSO or offloading buoy with and without an offtake tanker in tandem, a separate analysis for each mode shall be performed. For turret moored vessels where thrusters are used to actively control the vessel's heading, the way in which the vessel heading is chosen in each fatigue weather bin should be included in the fatigue analysis. Fatigue-life calculations shall be performed for all components in the mooring line.

8.7.2 Analysis Approach

Time-domain or frequency-domain dynamic analyses shall be used to determine load (tension or stress) ranges. When performing frequency-domain analysis, the standard deviations of low-frequency and wave-frequency tension components shall be calculated about the mean floating structure offset position for each fatigue weather bin. When performing time-domain analysis, the time history of the total tension (mean + low-frequency + wave-frequency contributions) can be directly derived from the analysis.

The net static-horizontal loads from risers can impact the fatigue performance of mooring lines and shall be included in the analysis. Where applicable, changes to the pretension of the mooring lines from the addition of future risers shall be accounted for, and conservative riser configurations shall be used for the fatigue analysis.

Where applicable, a sensitivity analysis should be performed for the range of loading conditions of the floating structure so that a conservative loading condition can be selected for the fatigue analysis.

The annual number of load cycles shall be determined separately for each load case (draft, trim, and riser configuration) and for each mooring line segment.

The T-N curves provided in 7.4 are based on pure tension-tension loading (i.e. tension loading without bending or torsion). The impact on fatigue life of mooring components (chain, wire rope, connectors, etc.) that are subject to loading that is not pure tension, e.g. chain in the fairlead, on bending shoes, in the thrash zone, at articulations and terminations, OPB, etc., shall be assessed using other methods. For these chain links that are subjected to more complex loading, the fatigue damage assessment methodology shall be approved by the owner. An example of a damage assessment for chain OPB fatigue is provided in A.8.7.2.

8.7.3 Fatigue Damage Calculation Methods

8.7.3.1 General

The general principle for fatigue damage calculation is the Palmgren-Miner linear damage hypothesis. That is, the annual fatigue damage accumulated in a mooring line component is the sum of the fatigue damage occurring in each of fatigue weather bins chosen to discretize the long-term environment that the mooring system is subjected to:

$$D = \sum_{i=1}^n D_i \quad (2)$$

where

D is the annual fatigue damage in a mooring line component, years⁻¹.

D_i is the annual fatigue damage arising in fatigue weather bin i , years⁻¹.

The calculated fatigue life, L , of the mooring system is given by:

$$L = 1/D \text{ years} \quad (3)$$

The annual fatigue damage accumulated in an individual bin is given by:

$$D_i = \frac{n_i}{N_i} = \frac{n_i}{K} E[R_i^m] \quad (4)$$

where

m and K are defined in Table 14;

n_i is the number of cycles at load range R_i occurring in the i th fatigue weather bin, per year;

N_i is the number of cycles to failure at load range R_i from Equation (1), per year;

$E[R_i^m]$ is the expected value of the normalized tension range R_i raised to the power m , in weather bin i .

The discretization into $i = 1, \dots, n$ environmental states, fatigue weather bins should be sufficiently detailed to avoid significant errors in the total. Each fatigue weather bin is defined in terms of the wind, sea-wave, swell-wave, and current parameters and directions required to compute mooring system responses. The probability of occurrence, P_i , is required for each fatigue weather bin. The number of tension cycles per year in each state can be determined from:

$$n_i = v_i \times T_i = v_i \times P_i \times 3.15576 \times 10^7 \quad (5)$$

where

v_i is the zero upcrossing frequency (hertz) of the tension spectrum in environmental state i ;

T_i is the time spent in environmental state i per year;

P_i is the probability of occurrence of environmental state i .

For nonstandard mooring line components such as shackles, H-links, tri-plates, and specialty connectors, fatigue damage shall be calculated using an appropriate S-N curve for the base material with hot spot stresses or SCF derived from FEA. When evaluating these nonstandard components using a S-N curve, Equation (4) is replaced by Equation (6).

$$D_i = \frac{n_i}{N_i} = \frac{n_i}{K_S} E[S_i^{m_S}] \quad (6)$$

where

m_S and K_S are the parameters of the S-N curve;

$E[S_i^{m_S}]$ is the expected value of the hot spot stress range S_i raised to the power m_S , in fatigue weather bin i .

8.7.3.2 Combining Wave-frequency and Low-frequency Fatigue Damage

The annual fatigue damage can be calculated from a load time history with a cycle counting method or from a response spectrum with a probabilistic method.

The most widely accepted method of cycle counting is the rainflow cycle counting method. Several rainflow cycle counting algorithms can be found in ASTM E1049-85.

Probabilistic methods make an assumption about the load process. For moored vessels in fatigue environmental conditions, the distribution of the tension peaks is described by a Rayleigh distribution. Most response spectra of mooring line tension are bimodal spectra with distinct peaks for low-frequency and wave-frequency tension components. The following section discusses the different methods available for combining low-frequency and wave-frequency fatigue damage.

The following methods may be used for combining the damage due to wave-frequency and low-frequency tension spectra.

- a) Simple Summation—Wave-frequency damage and low-frequency damage are calculated independently, and the total damage is taken as the sum of the two. This method is slightly nonconservative when low- and wave-frequency contributions to the total damage are similar. This method may be used when the total damage is dominated by either the wave- or low-frequency contribution. This method is helpful in understanding mooring system response because it is the only method which provides estimates of the relative contributions from low- and wave-frequency tensions to the total fatigue damage.

- b) **Combined Spectrum**—The standard deviations of wave-frequency tension ranges and low-frequency tension ranges are calculated independently based on the separate wave-frequency and low-frequency tension spectra or the separate wave-frequency and low-frequency tension time series; the standard deviation of the combined response is computed as the square root of the sum of the variances. The damage is then calculated using the combined standard deviation. This method is always conservative and may significantly overestimate the actual fatigue damage.
- c) **Combined Spectrum with Dual Narrow-banded Correction Factor**—A correction factor is applied to the result of the combined spectrum method presented in 8.7.3.2 b). This method is an improvement on method 8.7.3.2 b), which yields less-conservative predictions. It is suitable for cases where low- and wave-frequency contributions to the total damage are similar. However, when the fatigue damage is dominated by low-frequency tensions, this method will overestimate the fatigue damage.
- d) **Time-domain Cycle Counting**—Fatigue damage is calculated from a tension time history using a cycle counting method, such as the rainflow method, to estimate the magnitude and number of tension range cycles. The tension time history can be determined directly by a time-domain analysis, or it can be generated from the combined low- and wave-frequency spectral analyses. Time-domain cycle counting when rigorously performed with a sufficient number of simulations is often considered to be the most accurate method.

Formulae and discussion are provided in A.8.7.2.

8.7.3.3 Accounting for Mean Value of Tension in Wire Rope

Fatigue damage in steel wire rope depends on the mean value of the tension, as well as the tension range.

To account for this the mean tension, Q_i , shall be determined for each line segment in each fatigue weather bin i . The K parameter of the wire rope T-N curve shall then be calculated as a function of the mean tension Q (see Table 14).

8.7.3.4 Combining Wave-induced and VIM-induced Fatigue Damage

Fatigue damage from VIM shall be calculated separately and added to the fatigue damage from wind and wave-induced motions.

8.8 Response-based Analysis

Traditionally, global hydrodynamic or motion responses, which include mooring extreme response for strength design, have relied on deterministic analyses performed for a design environment with an AJP of $1/N$, i.e. an event with a combined return period of N -years (e.g. loss of heading control and winter storm conditions). In this approach, the extreme mooring system response (the N -year response) is implicitly assumed to occur in the extreme N -year return period condition. Floating structures and their station keeping systems are, generally, complex nonlinear systems. Due to the unique characteristics of each response mode, it is possible that N -year extreme responses may not occur in the N -year return period environmental condition.

An RBA can overcome this limitation. The target of the RBA approach is to determine the N -year return period extreme responses, rather than the extreme responses due to the N -year return period environment. An RBA is based on the response statistics (e.g. mooring line tension, vessel roll, vessel offset, etc.) using a long-term time series of metocean events instead of metocean statistics. It can be performed to supplement the responses of critical design variables estimated using the design environmental condition analysis. In the context of the mooring system design, critical design variables to be considered in an RBA may include the following: